e-FILING REPORT COVER SHEET

COMPANY NAME: NW Natural

DOES REPORT CONTAIN CONFIDENTIAL INFORMATION? ☒ No ☐ Yes If yes, submit a redacted public version (or a cover letter) by email. Submit the confidential information as directed in OAR 860-001-0070 or the terms of an applicable protective order.

Select report type: ☐ RE (Electric) ☒ RG (Gas) ☐ RW (Water) ☐ RT (Telecommunications)
☐ RO (Other, for example, industry safety information)

Did you previously file a similar report? ☐ No ☒ Yes, report docket number: RG 37

Report is required by: ☒ OAR 860-027-0070
☐ Statute
☐ Order
Note: A one-time submission required by an order is a compliance filing and not a report (file compliance in the applicable docket)
☐ Other
(For example, federal regulations, or requested by Staff)

Is this report associated with a specific docket/case? ☐ No ☒ Yes, docket number: RG 37

List Key Words for this report. We use these to improve search results.

2017 Annual Report for year ending December 31, 2017, FERC Form 2

Send the completed Cover Sheet and the Report in an email addressed to PUC.FilingCenter@state.or.us

Send confidential information, voluminous reports, or energy utility Results of Operations Reports to PUC Filing Center, PO Box 1088, Salem, OR 97308-1088 or by delivery service to 201 High Street SE Suite 100, Salem, OR 97301.

Print

MARK R. THOMPSON
Sr. Director, Rates & Regulatory Affairs
Tel: 503.721.2476
Fax: 503.721.2516
Email: mark.thompson@nwnatural.com

NW Natural
220 NW 2ND AVENUE
PORTLAND, OR 97209
TEL 503.226.4211
www.nwnatural.com

April 30, 2018

VIA ELECTRONIC FILING AND US MAIL

Public Utility Commission of Oregon
Attn: Filing Center
201 High Street SE, Suite 100
Salem, Oregon 97301-3398

Re: RG 37 – Annual Report for the year ending December 31, 2017
FERC Form 2, Oregon Supplement to FERC Form 2, and Annual Report to Shareholders

In accordance with OAR 860-027-0070, Northwest Natural Gas Company, dba NW Natural ("NW Natural" or "Company") files herewith its Annual Report and the Oregon Supplement to the Public Utility Commission of Oregon for the year ended December 31, 2017. The report is submitted on forms (FERC Form 2) provided by the Commission. Also attached is the Oregon copy of the Company's Annual Report to Shareholders. Hard copies of the reports will be provided upon request. Two CDs containing the Oregon Supplement in a Microsoft Excel workbook will be sent via US mail. One of these CDs will be addressed to PUC staff member Marianne Gardner.

Please address any correspondence on this matter to me, with copies to Mr. Brody Wilson, Vice President, CAO, Controller & Treasurer, at the address above.

Sincerely,

/s/ Mark R. Thompson

Mark R. Thompson
Sr. Director, Rates & Regulatory Affairs

Attachments

F.P.C. Form No. 2 | Form approved.

UBI: 93-0256722 | Budget Bureau No. 54-R009

NATURAL GAS COMPANIES

(Class A and B)

ANNUAL REPORT

OF

NORTHWEST NATURAL GAS COMPANY

(Exact Legal Name of Respondent)

If name was changed during year, show also the previous name and date of change

PORTLAND, OREGON

(Address of Principal Business Office at End of Year)

TO THE

PUBLIC UTILITY COMMISSION OF OREGON

AND

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

FOR THE

YEAR ENDED DECEMBER 31, 2017

Name, Title, and address of officer or other person to whom should be addressed any communication concerning this report:

Brody J. Wilson, Vice President, Chief Accounting Officer, Controller and Treasurer
220 N.W. Second Avenue
Portland, Oregon 97209

THIS FILING IS	
Item 1: ☒ An Initial (Original Submission)	OR ☐ Resubmission No. ____

Form 2 Approved
OMB No. 1902-0028
(Expires 12/31/2020)

Form 3-Q Approved
OMB No. 1902-0205
(Expires 12/31/2019)

FERC FINANCIAL REPORT
FERC FORM No. 2: Annual Report of Major Natural Gas Companies and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Natural Gas Act, Sections 10(a), and 16 and 18 CFR Parts 260.1 and 260.300. Failure to report may result in criminal fines, civil penalties, and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of a confidential nature.

Exact Legal Name of Respondent (Company)	Year/Period of Report
NW NATURAL GAS COMPANY	**End of** 12/31/2017

INSTRUCTIONS FOR FILING FERC FORMS 2, 2-A and 3-Q

GENERAL INFORMATION

I Purpose

FERC Forms 2, 2-A, and 3-Q are designed to collect financial and operational information form natural gas companies subject to the jurisdiction of the Federal Energy Regulatory Commission. These reports are also considered to be a non-confidential public use forms.

II. Who Must Submit

Each natural gas company whose combined gas transported or stored for a fee exceed 50 million dekatherms in each of the previous three years must submit FERC Form 2 and 3-Q.

Each natural gas company not meeting the filing threshold for FERC Form 2, but having total gas sales or volume transactions exceeding 200,000 dekatherms in each of the previous three calendar years must submit FERC Form 2-A and 3-Q.

Newly established entities must use projected data to determine whether they must file the FERC Form 3-Q and FERC Form 2 or 2-A.

III. What and Where to Submit

(a) Submit Forms 2, 2-A and 3-Q electronically through the submission software at http://www.ferc.gov/docs-filing/eforms/form-2/elec-subm-soft.asp .

(b) The Corporate Officer Certification must be submitted electronically as part of the FERC Form 2 and 3-Q filings.

(c) Submit immediately upon publication, by either eFiling or mailing two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders and any annual financial or statistical report regularly prepared and distributed to bondholders, security analysts, or industry associations. Do not include monthly and quarterly reports. Indicate by checking the appropriate box on Form 2, Page 3, List of Schedules, if the reports to stockholders will be submitted or if no annual report to stockholders is prepared. Unless eFiling the Annual Report to Stockholders, mail these reports to the Secretary of the Commission at:

Secretary of the Commission
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

(d) For the Annual CPA certification, submit with the original submission of this form, a letter or report (not applicable to respondents classified as Class C or Class D prior to January 1, 1984) prepared in conformity with the current standards of reporting which will:

(i) Contain a paragraph attesting to the conformity, in all material respects, of the schedules listed below with the Commission's applicable Uniform Systems of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and

(ii) be signed by independent certified public accountants or an independent licensed public accountant certified or licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 C.F.R. §§158.10-158.12 for specific qualifications.)

Reference	Reference Schedules Pages
Comparative Balance Sheet	110-113
Statement of Income	114-117
Statement of Retained Earnings	118-119
Statement of Cash Flows	120-121
Notes to Financial Statements	122-123

Filers should state in the letter or report, which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist.

(e) Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. To further that effort, new selections, "Annual Report to Stockholders" and "CPA Certification Statement," have been added to the dropdown "pick list" from which companies must choose when eFiling. Further instructions are found on the Commission website at http://www.ferc.gov/help/how-to.asp

(f) Federal, State and Local Governments and other authorized users may obtain additional blank copies of FERC Form 2 and 2-A free of charge from: http://www.ferc.gov/docs-filing/eforms/form-2/form-2.pdf and http://www.ferc.gov/docs-filing/eforms/form-2a/form-2a.pdf, respectively. Copies may also be obtained from the Public Reference and Files Maintenance Branch, Federal Energy Regulatory Commission, 888 First Street, NE. Room 2A, Washington, DC 20426 or by calling (202). 502-8371

IV. When to Submit:

FERC Forms 2, 2-A, and 3-Q must be filed by the dates:

(a) FERC Form 2 and 2-A --- by April 18th of the following year (18 C.F.R. §§ 260.1 and 260.2)

(b) FERC Form 3-Q --- Natural gas companies that file a FERC Form 2 must file the FERC Form 3-Q within 60 days after the reporting quarter (18 C.F.R.§ 260.300), and

(c) FERC Form 3-Q --- Natural gas companies that file a FERC Form 2-A must file the FERC Form 3-Q within 70 days after the reporting quarter (18 C.F.R. § 260.300).

V. Where to Send Comments on Public Reporting Burden.

The public reporting burden for the Form 2 collection of information is estimated to average 1,623 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data-needed, and completing and reviewing the collection of information. The public reporting burden for the Form 2A collection of information is estimated to average 250 hours per response. The public reporting burden for the Form 3-Q collection of information is estimated to average 165 hours per response.

Send comments regarding these burden estimates or any aspect of these collections of information, including suggestions for reducing burden, to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 (Attention: Information Clearance Officer); and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 (Attention: Desk Officer for the Federal Energy Regulatory Commission). No person shall be subject to any penalty if any collection of information does not display a valid control number (44 U.S.C. § 3512 (a)).

GENERAL INSTRUCTIONS

I. Prepare all reports in conformity with the Uniform System of Accounts (USofA) (18 C.F.R. Part 201). Interpret all accounting words and phrases in accordance with the USofA.

II. Enter in whole numbers (dollars or Dth) only, except where otherwise noted. (Enter cents for averages and figures per unit where cents are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required.) The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting period, and use for statement of income accounts the current year's year to date amounts.

III. Complete each question fully and accurately, even if it has been answered in a previous report. Enter the word "None" where it truly and completely states the fact.

IV. For any page(s) that is not applicable to the respondent, omit the page(s) and enter "NA," "NONE," or "Not Applicable" in column (d) on the List of Schedules, pages 2 and 3.

V. Enter the month, day, and year for all dates. Use customary abbreviations. **The "Date of Report" included in the header of each page is to be completed only for resubmissions**.

VI. Generally, except for certain schedules, all numbers, whether they are expected to be debits or credits, must be reported as positive. Numbers having a sign that is different from the expected sign must be reported by enclosing the numbers in parentheses.

VII. For any resubmissions, submit the electronic filing using the form submission only. Please explain the reason for the resubmission in a footnote to the data field.

VIII. Footnote and further explain accounts or pages as necessary.

IX. Do not make references to reports of previous periods/years or to other reports in lieu of required entries, except as specifically authorized.

X. Wherever (schedule) pages refer to figures from a previous period/year, the figures reported must be based upon those shown by the report of the previous period/year, or an appropriate explanation given as to why the different figures were used.

XI. Report all gas volumes in Dth unless the schedule specifically requires the reporting in another unit of measurement.

DEFINITIONS	
I.	Btu per cubic foot -- The total heating value, expressed in Btu, produced by the combustion, at constant pressure, of the amount of the gas which would occupy a volume of 1 cubic foot at a temperature of 60°F if saturated with water vapor and under a pressure equivalent to that of 30°F, and under standard gravitational force (980.665 cm. per sec) with air of the same temperature and pressure as the gas, when the products of combustion are cooled to the initial temperature of gas and air when the water formed by combustion is condensed to the liquid state (called gross heating value or total heating value).
II.	Commission Authorization -- The authorization of the Federal Energy Regulatory Commission, or any other Commission. Name the commission whose authorization was obtained and give date of the authorization.
III.	Dekatherm -- A unit of heating value equivalent to 10 therms or 1,000,000 Btu.
IV.	Respondent -- The person, corporation, licensee, agency, authority, or other legal entity or instrumentality on whose behalf the report is made.

EXCERPTS FROM THE LAW (Natural Gas Act, 15 U.S.C. 717-717w)

"Sec. 10(a). Every natural-gas company shall file with the Commission such annual and other periodic or special reports as the Commission may by rules and regulations or order prescribe as necessary or appropriate to assist the Commission in the proper administration of this act. The Commission may prescribe the manner and form in which such reports shall be made and require from such natural-gas companies specific answers to all questions upon which the Commission may need information. The Commission may require that such reports include, among other things, full information as to assets and liabilities, capitalization, investment and reduction thereof, gross receipts, interest dues and paid, depreciation, amortization, and other reserves, cost of facilities, costs of maintenance and operation of facilities for the production, transportation, delivery, use, or sale of natural gas, costs of renewal and replacement of such facilities, transportation, delivery, use and sale of natural gas..."

"Section 16. The Commission shall have power to perform all and any acts, and to prescribe, issue, make, amend, and rescind such orders, rules, and regulations as it may find necessary or appropriate to carry out the provisions of this act. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this act; and may prescribe the form or forms of all statements declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and time within they shall be filed..."

General Penalties

The Commission may assess up to $1 million per day per violation of its rules and regulations. See NGA § 22(a), 15 U.S.C. § 717t-1(a).

FERC FORM NO. 2:

ANNUAL REPORT OF MAJOR NATURAL GAS COMPANIES

IDENTIFICATION		
01 Exact Legal Name of Respondent Northwest Natural Gas Company	**02 Year of Report** December 31, 2017	
03 Previous Name and Date of Change (If name changed during year)		
04 Address of Principal Office at End of Year (Street, City, State, Zip Code) 220 N.W. Second Avenue, Portland, Oregon 97209		
05 Name of Contact Person Brody J. Wilson	**Title of Contact Person** Vice President, Chief Accounting Officer, Controller and Treasurer	
07 Address of Contact Person (Street, City, State, Zip Code) 220 N.W. Second Avenue, Portland, Oregon 97209		
08 Telephone of Contact Person, Including Area Code (503) 226-4211	**This Report Is:** (1) ☒ An Original (2) ☐ A Resubmission	**10 Date of Report (Mo, Day, Yr)** April 30, 2018

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.

11 Name Brody J. Wilson	**12 Title** Vice President, Chief Accounting Officer, Controller and Treasurer
13 Signature 	**14 Date Signed (Mo, Day, Yr)** April 26, 2018

Title 18, U.S.C. 1001, makes it a crime for any person knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.

Name of Respondent	This Report is:	Date of Report	Year of Report
	(1) ☒ An Original	(Mo, Da, Yr)	
Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

List of Schedules (Natural Gas Company)

Enter in Column (d) the terms "none", "not applicable", or "NA" as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the responses are "none", "not applicable", or "NA".

List of Schedules (Natural Gas Company)

Enter in Column (d) the terms "none", "not applicable", or "NA" as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the responses are "none", "not applicable", or "NA".

Line No.	Title of Schedule (a)	Reference Page Number (b)	Date Revised (c)	Remarks (d)
38	Unamortized Loss and Gain on Reacquired Debt	260		
39	Reconciliation of Reported Net Income with Taxable Income for Federal Income Taxes	261		
40	Taxes Accrued, Prepaid, and Charged During Year	262-263		
41	Miscellaneous Current and Accrued Liabilities	268		
42	Other Deferred Credits	269		
43	Accumulated Deferred Income Taxes-Other Property	274-275		NA
44	Accumulated Deferred Income Taxes-Other	276-277		
45	Other Regulatory Liabilities	278		
	INCOME ACCOUNT SUPPORTING SCHEDULES			
46	Monthly Quantity & Revenue Data by Rate Schedule	299		NA
47	Gas Operating Revenues	300-301		
48	Revenues from Transportation of Gas of Others Through Gathering Facilities	302-303		NA
49	Revenues from Transportation of Gas of Others Through Transmission Facilities	304-305		NA
50	Revenues from Storage Gas of Others	306-307		NA
51	Other Gas Revenues	308		
52	Discounted Rate Services and Negotiated Rate Services	313		NA
53	Gas Operation and Maintenance Expenses	317-325		
54	Exchange and Imbalance Transactions	328		NA
55	Gas Used in Utility Operations	331		
56	Transmission and Compression of Gas by Others	332		NA
57	Other Gas Supply Expenses	334		NA
58	Miscellaneous General Expenses-Gas	335		
59	Depreciation, Depletion, and Amortization of Gas Plant	336-338		
60	Particulars Concerning Certain Income Deduction and Interest Charges Accounts	340		
	COMMON SECTION			
61	Regulatory Commission Expenses	350-351		
62	Employee Pensions and Benefits (Account 926)	352		
63	Distribution of Salaries and Wages	354-355		
64	Charges for Outside Professional and Other Consultative Services	357		
65	Transactions with Associated (Affiliated) Companies	358		
	GAS PLANT STATISTICAL DATA			
66	Compressor Stations	508-509		
67	Gas Storage Projects	512-513		
68	Transmission Lines	514		
69	Transmission System Peak Deliveries	518		NA
70	Auxiliary Peaking Facilities	519		
71	Gas Account-Natural Gas	520		
72	Shipper Supplied Gas for the Current Quarter	521		NA
73	System Map	522		NA
74	Footnote Reference	551		NA
75	Footnote Text	552		NA
76	Stockholder's Reports (check appropriate box)			
	☐ Four copies will be submitted ☐ No annual report to stockholders is prepared			

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	(1) ☒ An Original (2) ☐ A Resubmission		December 31, 2017

GENERAL INFORMATION

1. Provide name and title of officer having custody of the general corporate books of account and address of office where the general corporate books are kept and address of office where any other corporate books of account are kept, if different from that where the general corporate books are kept.

Brody J. Wilson **Vice President, Chief Accounting Officer, Controller and Treasurer**

220 N.W. Second Avenue, Portland, Oregon 97209

2. Prove the name of the State under the laws of which respondent is incorporated and date of incorporation. If incorporated under a special law, give reference to such law. If not incorporated, state that fact and give the type of organization and the date organized.

State of Oregon **January 10, 1910**

3. If at any time during the year the property of respondent was held by a receiver or trustee, give (a) name of receiver or trustee, (b) date such receiver or trustee took possession, (c) the authority by which the receivership of trusteeship was created, and 9d) date when possession by receiver or trustee ceased.

NOT APPLICABLE

4. State the classes of utility and other services furnished by respondent during the year in each State in which the respondent operated.

GAS SERVICE IN OREGON AND WASHINGTON

5. Have you engaged as the principal accountant to audit your financial statements an accountant who is not the principal accountant for your previous year's certified financial statements?

(1) ☐ Yes...Enter the date when such independent account was initially engaged _______________

(2) ☒ No

Name of Respondent	This Report is:	Date of Report	Year of Report
	(1) ☒ An Original	(Mo, Da, Yr)	
Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

CORPORATIONS CONTROLLED BY RESPONDENT

1. Report below the names of all corporations, business trusts, and similar organizations, controlled directly or indirectly by respondent at any time during the year. If control ceased prior to end of year, give particulars (details) in a footnote.

2. If control was by other means than a direct holding of voting rights, state in a footnote the manner in which control was held, naming any intermediaries involved.

3. If control was held jointly with one or more other interests, state the fact in a footnote and name the other interests.

4. In column (b) designate type of control of the respondent as "D" for direct, an "I" for indirect, or a "J" for joint control.

DEFINITIONS

1. See the Uniform System of Accounts for a definition of control.

2. Direct control is that which is exercised without interposition of an intermediary.

3. Indirect control is that which is exercised by the inter-position of an intermediary which exercises direct control.

4. Joint control is that in which neither interest can effectively control or direct action without the consent of the other, as where the voting control is equally divided between two holders, or each party holds a veto power over the other. Joint control may exist by mutual agreement or understanding between two or more parties who together have control within the meaning of the definition of control in the Uniform System of Accounts, regardless of the relative voting rights of each party.

Line No.	Name of Company Controlled (a)	Type of Control (b)	Kind of Business (c)	Percent Voting Stock Owned	Footnote Ref. (d)
1	Gill Ranch Storage, LLC	I	Gas storage	100%	1
2	NW Natural Energy, LLC	D	Intermediate holding company	100%	2
3	NW Natural Gas Storage, LLC	I	Gas storage	100%	3
4	NNG Financial Corporation	D	Financing and investments	100%	4
5	Trail West Holdings, LLC	I/J	Intermediate holding company	50%	5
6	Trail West Pipeline, LLC	I/J	Gas transmission company	*	6
7	BL Credit Holdings, LLC	I/J	Non-operating company	*	7
8	Northwest Biogas, LLC	J	Biodigester company	50%	8
9	KB Pipeline Company	I	Gas transmission company	100%	9
10	Northwest Energy Corporation	D	Intermediate holding company	100%	10
11	Northwest Energy Sub Corporation	I	Non-operating company	100%	11
12	NWN Gas Reserves, LLC	I	Gas reserves	100%	12
13	NW Natural Water Company, LLC	D	Holding company	100%	13
14	FWC Merger Sub, Inc.	I	Non-operating company	100%	14

1	Gill Ranch Storage, LLC, a wholly-owned subsidiary of NW Natural Gas Storage, LLC, was formed in 2007 as part of a joint project with Pacific Gas & Electric to develop, own and operate an underground natural gas storage facility near Fresno, California. Gill Ranch began commercial operations in 2010.
2	NW Natural Energy, LLC, a wholly-owned subsidiary, is a holding company. Primarily used for gas storage and other non-utility investments.
3	NW Natural Gas Storage, LLC, a wholly-owned subsidiary of NW Natural Energy, LLC, primarily contains the operating employees for our gas storage businesses.
4	NNG Financial Corporation, a wholly-owned subsidiary, commenced operations in September 1990. NNG Financial Corporation holds certain non-utility financial investments but its assets primarily consist of an active wholly-owned subsidiary KB Pipeline Company.
5	Trail West Holdings, LLC (formerly Palomar Gas Holdings, LLC) a joint venture with TransCanada American Investments, Ltd. and 50% ownership subsidiary of NW Natural Energy, LLC, is designed to be the holding company for Trail West operating companies.
6	Trail West Pipeline, LLC (formerly Palomar Gas Transmission, LLC), wholly-owned by Trail West Holdings, LLC, was formed in 2007 to develop an interstate gas pipeline.
7	BL Credit Holdings, LLC, wholly-owned by Trail West Pipeline, LLC, is currently not operating.
8	Northwest Biogas, LLC, an equal joint venture with BEF Renewable Incorporated, was formed in 2008 to develop a biodigester.
9	KB Pipeline company, a wholly-owned subsidiary of NNG Financial Corporation, owns a 10% interest in an interstate natural gas pipeline.
10	Northwest Energy Corporation, is a wholly-owned subsidiary, primarily used as a holding company of NWN Gas Reserves, LLC.
11	Northwest Energy Sub Corporation, is an inactive and indirect subsidiary.
12	NWN Gas Reserves, LLC, a wholly-owned subsidiary of Northwest Energy Corporation, was formed in 2012 as part of a joint venture with Encana Oil & Gas (USA) Inc. to develop, own and operate gas reserves. In 2014, Encana Oil & Gas (USA) Inc. sold its interest in the gas reserves to Jonah Energy LLC.
13	NW Natural Water Company, LLC, a wholly-owned subsidiary, was formed in 2017 and is pursuing investments in the water sector itself and through its wholly-owned subsidiary FWC Merger Sub, Inc.
14	FWC Merger Sub, Inc., a wholly-owned subsidiary of NW Natural Water Company, LLC was formed in 2017 as a non-operating merger subsidiary in the event of an acquisition of a water company.
*	These companies are 100% owned indirectly through our joint venture Trail West Holdings, LLC.

SECURITY HOLDERS AND VOTING POWERS

1. Give the names and addresses of the 10 security holders of the respondent who, at the date of the latest closing of the stock book or compilation of list of stockholders of the respondent, prior to the end of the year, had the highest voting powers in the respondent, and state the number of votes which each would have had the right to cast on that date if a meeting were then in order. If any such holder held in trust, give in a footnote the known particulars of the trust (whether voting trust, etc.), duration of trust, and principal holders of beneficiary interests in the trust. If the stock book was not closed or a list of stock-holders was not compiled within one year prior to the end of the year, or if since the previous compilation of a list of stockholders, some other class of security has become vested with voting rights, then show such 10 security holders as of the close of the year. Arrange the names of the security holders in the order of voting power, commencing with the highest. Show in column (a) the titles of officers and directors included in such list of 10 security holders.

2. If any security other than stock carries voting rights, explain in a supplemental statement the circumstances whereby such security became vested with voting rights and give other important particulars (details) concerning the voting rights of such security. State whether voting rights are actual or contingent; if contingent, describe the contingency.

3. If any class or issue of security has any special privileges in the election of directors, trustees or managers, or in the determination of corporate action by any method, explain briefly in a footnote.

4. Furnish details concerning any options, warrants, or rights outstanding at the end of the year for others to purchase securities of the respondent or any securities or other assets owed by the respondent, including prices, expiration dates, and other material information relating to exercise of the options, warrants, or rights. Specify the amount of such securities or assets so entitled to be purchased by any officer, director, associated company, or any of the ten largest security holders. This instruction is inapplicable to convertible securities or to any securities substantially all of which are outstanding in the hands of the general public where the options, warrants, or rights were issued on a prorata basis.

1. Give date of the latest closing of the stock book prior to end of year, and, in a footnote,state the purpose of such closing:	2. State the total number of votes cast at the latest general meeting prior to the end of year for election of directors of the respondent and number of such votes cast by proxy.	3. Give the date and place of such meeting:
10/31/2017, list of stockholders to whom dividends were paid on 11/15/2017	Total: 19,967,945 By Proxy: 19,169,058	Date: 5/25/2017 Place: Portland, Oregon Location: Northwest Natural Gas Company Headquarters

Line No.	Name (Title) and Address of Security Holder (a)	VOTING SECURITIES 4. Number of votes as of (date): Total Votes (b)	Common Stock (c)	Preferred Stock (d)	Other (e)
5	TOTAL votes of all voting securities	28,713,052	28,713,052		
6	TOTAL number of security holders	5,276	5,276		
7	TOTAL votes of security holders listed below	26,545,428	26,545,428		
8					
9	**See page 107 B**				
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

SECURITY HOLDERS AND VOTING POWERS (Continued)

Line No.	Name and Address (1a) (a)	Shares of Common Stock (b)	Percentage of Stock Outstanding (Voting Control) (c)
1	Cede & Company[(1)]	26,346,482	91.76%
2	P.O. Box 20		
3	Bowling Green Station		
4	New York, NY 10004-1408		
5	David H. Anderson &[(2)]	63,483	0.22%
6	Susan S. Anderson JT TEN		
7	1688 Leslie Ln		
8	Lake Oswego, OR 97034-2179		
9	Wachovia Bank N.A. TTEE[(3)]	23,323	0.08%
10	Northwest Natural Gas Co Umbrella TR for Directors		
11	DTD 1-1-91 Restated 12/15/05 for A/C Exec Serv		
12	One West Fourth St NC 6251		
13	Winston-Salem, NC 27101		
14	Mary Susan Pape[(4)]	21,207	0.07%
15	3693 North Shasta Loop		
16	Eugene, OR 97405		
17	Daniel J. Clement &	21,064	0.07%
18	Elizabeth J. Clement JT TEN		
19	303 Lakeside Drive		
20	Lewisburg, PA 17837		
21	Wachovia Bank N.A. TTEE[(5)]	16,207	0.06%
22	Northwest Natural Gas Co Umbrella TR for Directors		
23	DTD 1-1-91 Restated 12/15/05 NEDSCP A/C Exec Serv		
24	One West Fourth St NC 6251		
25	Winston-Salem, NC 27101		
26	Mervin J. Schafer & Sharan L. Schafer, Trustees of	14,312	0.05%
27	Mervin J. & Sharan L. Schafer Living Trust UA DTD Sept. 16, 2011		
28	P.O. Box 3288		
29	Salem, OR 97302-0288		
30	Margaret D. Kirkpatrick[(6)]	13,763	0.05%
31	2241 NE 30th Avenue		
32	Portland, OR 97212		
33	Robert C. Reverman & Patricia H. Reverman, Trustees of	13,587	0.05%
34	The Reverman Family Trust UTD 1/12/1994		
35	170 Kala Heights Drive		
36	Port Townsend, WA 98368-9596		
37	Gekay Inc.	12,000	0.04%
38	P.O. Box 701		
39	Lafayette, NJ 07848		

(1) Per Schedule 13G/A's filed with the SEC by BlackRock, Inc., 55 East 52nd Street, New York, NY 10055, and The Vanguard Group, Inc., 100 Vanguard Boulevard, Malvern, PA 19355, as of December 31, 2017, each held shares through Cede & Company, and was a beneficial owner of 13.10%, and 10.03%, respectively, of NW Natural common stock. Additionally, pursuant to NW Natural's Proxy Solicitor, D.F. King & Co., Inc., as of December 31, 2017, Dimensional Fund Advisors, Duff & Phelps Investment Management, State Street Global Advisors, Invesco Powershares Capital Management LLC, GAMCO Investors, Inc., Bank of New York Mellon Corp., Norges Bank Investment Management, and Parnassus Investment Management, each held shares through Cede & Company, and was a beneficial owner of 3.08%, 2.78%, 2.72%, 1.68%, 1.61%, 1.57%, 1.53% and 1.43%, respectively, of NW Natural common stock.

(2) President and Chief Executive Officer, effective August 1, 2016; and formerly President and Chief Operating Officer through July 31, 2016.

(3) Current, Retired and Former Directors - Timothy P. Boyle, Martha L. Byorum, John D. Carter, Tod R. Hamacheck, Wayne D. Kuni, Randall C. Papé & Richard L. Woolworth.

(4) Beneficiary of former director.

(5) Current, Retired and Former Directors - Timothy P. Boyle, Martha L. Byorum, John D. Carter, Thomas E. Dewey, C. Scott Gibson, Tod R. Hamacheck, Wayne D. Kuni, Richard G. Reiten, Robert L. Ridgley, Melody Teppola, Russell F. Tromely & Richard L. Woolworth.

(6) Retired Senior Vice President, Environmental Policy and Affairs, effective December 31, 2015.

SECURITY HOLDERS AND VOTING POWERS (Continued)

Line No.	Name and Address (1a) (a)	Shares of Common Stock (b)		Percentage of Stock Outstanding (Voting Control) (c)
41	**Officers**	**Stock Option for Officers as of 12/31/2017**	**Stock Rights for Officers as of 12/31/2017**[1]	
42	David H. Anderson	19,000	31,810	*
43	Frank Burkhartsmeyer	—	10,816	*
44	Lea Anne Doolittle	11,000	9,897	*
45	James R. Downing	—	5,340	*
46	Shawn M. Filippi	600	5,333	*
47	Kimberly A. Heiting	5,500	5,700	*
48	Thomas J. Imeson	—	8,072	*
49	Justin Palfreyman	—	5,662	*
50	Lori L. Russell	4,700	3,612	*
51	MardiLyn Saathoff	7,000	16,345	*
52	David A. Weber	7,000	1,022	*
53	Brody J. Wilson	—	5,775	*
54	Grant M. Yoshihara	7,500	8,093	*
55	**Directors**		**Stock Rights for Directors as of 12/31/2017**[2]	
56	Timothy P. Boyle		328	*
57	Martha "Stormy" L. Byorum		328	*
58	John D. Carter		328	*
59	Mark S. Dodson		328	*
60	C. Scott Gibson		328	*
61	Tod R. Hamachek		328	*
62	Jane L. Peverett		328	*
63	Kenneth Thrasher		328	*
64	Malia H. Wasson		328	*

(1) Includes performance based stock and performance/time based restricted stock units

(2) Time based restricted stock units

* Less than one percent.

IMPORTANT CHANGES DURING THE YEAR

Give details concerning the matters indicated below. Make the statements explicit and precise, and number them in accordance with the inquiries. Answer each inquiry. Enter "none" or "not applicable" where applicable. If the answer is given elsewhere in the report, refer to the schedule in which it appears.

1. Changes in and important additions to franchise rights: Describe the actual consideration and state from whom the franchise rights were acquired. If the franchise rights were acquired without the payment of consideration, state that fact.

2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.

3. Purchase or sale of an operating unit or system: Briefly describe the property, and the related transactions, and cite Commission authorization, if any was required. Give date journal entries called for by Uniform Systems of Accounts were submitted to the Commission.

4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other conditions. State name of Commission authorizing lease and give reference to such authorization.

5. Important extension or reduction or transmission or distribution system: State territory added or relinquished and date operations began or ceased and cite Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service.

Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.

6. Obligations incurred or assumed by respondent as guarantor for the performance by another of any agreement or obligation, including ordinary commercial paper maturing on demand or not later than one year after date of obligation. Cite commission authorization if any was required.

7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.

8. State the estimated annual effect and nature of any important wage scale changes during the year.

9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings

10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder, voting trustee, associated company or know associate of any of these persons was a party or in which any such person had a material interest.

11. Estimated increase or decrease in annual revenues caused by important rate changes: State effective date and approximate amount of increase or decrease for each revenue classification. State the number of customers affected.

12. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.

13. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s).Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.

See Page 108 B

IMPORTANT CHANGES DURING THE YEAR (Continued)

1. None

2. None

3. None

4. None

5. Reference to the 2016 Integrated Resource Plan that covers fiscal years 2016 and 2017 and the Gas Utility New Construction Budget for 2017 submitted to the Oregon Public Utilities Commission (OPUC) and the Washington Utilities and Transportation Commission (WUTC).

6. None

7. Effective December 21, 2017, the Board of Directors approved amendments to Article III, Section 1 of the Company's Bylaws to provide that, unless otherwise determined by the Board of Directors, no person who has reached the age of 75 years should be eligible to be elected a director. Previously, this provision of the Company's Bylaws provided that, unless otherwise determined by the Board of Directors, no person who has reached the age of 73 years shall be eligible to be elected a director. The Board of Directors also amended Article III, Section 2 of the Company's Bylaws to modify the progression of whom serves as Chair of the Board in the absence of the elected Chair, and amended the schedule for regular meetings of the Board of Directors provided in Article IV, Section 1.

8. Bargaining unit pay increase of 3.00% effective December 1, 2017.
Non-bargaining unit annual salary increase of approximately 3.00% effective March 1, 2017.

9. Reference is made to NOTE 15 - Environmental Matters of the Notes to the Financial Statements, beginning on Page 122-A.

10. The below describes certain transactions of the respondent in which an officer, director, security holder, voting trustee, associated company or known associate of any of these persons was a party or in which such person had a material interest. However, the below transactions are not materially important transactions of the respondent and the below response is not to be construed as an indication that the respondent deems such transactions as materially important.

Ted Smart, the husband of Lea Anne Doolittle, Senior Vice President and Chief Administrative Officer, has been an employee of NW Natural since February 2006. In November 2006, Mr. Smart moved from his position as a senior auditor to purchasing manager. Ms. Doolittle was not involved in decisions regarding Mr. Smart's hiring, promotion or compensation. Compensation paid to Mr. Smart in 2017 was approximately $212 thousand. Mr. Smart reports to the Senior Vice President and Chief Financial Officer. Compensation paid to Mr. Smart is reviewed periodically by the Audit Committee in accordance with our Transactions with Related Persons Policy.

Ms. Shawn M. Filippi, Vice President, Chief Compliance Officer and Corporate Secretary, is married to a Co-Managing Partner of the Portland office of Stoel Rives LLP. For many years prior to Ms. Filippi's employment at NW Natural, the Company engaged the law firm Stoel Rives LLP as outside legal counsel. The Company continues to engage Stoel Rives LLP from time to time, and intends to do so in the future. Total fees paid to Stoel Rives LLP in 2017 were approximately $1.1 million. Ms. Filippi's husband is not compensated by Stoel Rives LLP based on work performed for the Company and does not routinely work on Company matters. Furthermore, his interest is less than 1% of Stoel Rives' partnership allocation and the annual fees paid by the Company to Stoel Rives LLP in 2017 represented less than 1% of Stoel Rives LLP's annual gross revenues.

Reference to FERC Form No. 2 page 358 Transactions with Associated (Affiliated) Companies.

11. **Increase or decrease in annual revenues caused by important rate changes:**

OREGON

OREGON: The PGA and other related filings were made in the fall. Rates went into effect on November 1, 2017. The combined effects of these filings were approved in a number of dockets through OPUC Order 17-415 on October 16, 2017. The approval of these filings decreased the Company's annual Oregon revenues by $41.2 million, or 6.4 percent, passing through certain purchased gas cost adjustments, and technical adjustments amortizing the Company's deferred revenue and gas costs and other accounts. As of June 30, 2017, 650,501 customers were affected.

OREGON RATE CASE

2017 General Rate Case

On December 29, 2017, Northwest Natural Gas Company (NW Natural), for the first time since 2011, has filed for a general rate increase with the Public Utility Commission of Oregon (OPUC). The filing includes a requested $52.4 million annual revenue requirement increase, or a net revenue increase of $40.4 million or about 6% after an adjustment for the Company's conservation tariff deferral. The revenue requirement is based upon the following assumptions or requests:

Capital structure of 50% debt and 50% equity;
Return on equity of 10%
Cost of capital of 7.62%; and
Rate base of $1.19 billion or an increase of $304 million since the last rate case.

This general rate case filing does not include the impact of the newly passed federal tax legislation. The implications of tax reform will be addressed with the OPUC in the coming months through this general rate case filing or as part of other regulatory processes that could include all utilities in Oregon.

As previously reported, on December 29, 2017, Northwest Natural Gas Company (NW Natural) filed an application for a general rate increase with the Public Utility Commission of Oregon (OPUC). The rate case filing did not include the impact of newly passed federal tax legislation, but was filed with the intent that NW Natural would make supplemental filings to reflect the implications of tax reform on NW Natural's rates. On March 20, 2018, NW Natural made supplemental filings in the rate case to reflect the impact of tax reform. These supplemental filings reduce the requested annual revenue requirement increase from $52.4 million to $37.8 million, and reduce the net revenue increase requested from $40.4 million, or approximately 6%, to $25.7 million, or approximately 4%, after an adjustment for the Company's conservation tariff deferral. The revised revenue requirement is based upon the following assumptions or requests:

Forward test year from November 1, 2018 through October 31, 2019;
Capital structure of 50% debt and 50% equity;
Return on equity of 10.0%;
Cost of capital of 7.62%; and
Rate base of $1.215 billion or an increase of $329 million since the last rate case.

The supplement filings do not address the treatment of historical deferred tax liabilities, which may be addressed in either this rate case proceeding or in another proceeding and which may result in additional changes to the rate case request. New rates are anticipated to be effective November 1, 2018.

WASHINGTON

WASHINGTON: The PGA and energy efficiency filings were made in the fall. The new rates were allowed to go into effect, by operation of law, for service on and after November 1, 2017 at the WUTC Open Meeting held on October 27, 2017. The PGA filing revised rates for changes in purchased gas costs, and, both the PGA and energy efficiency filings updated temporary rate adjustments to amortize balances in deferred accounts. The combined effects of these filings decreased the Company's annual Washington revenues by $1.9 million, or 2.95 percent. As of June 30, 2017, 80,454 customers were affected.

12. Effective February 23, 2017, Justin Palfreyman was appointed Vice President, Strategy and Business Development. Mr. Palfreyman had been previously serving as Vice President, Business Development.
Effective May 17, 2017, Frank H. Burkhartsmeyer was appointed Senior Vice President and Chief Financial Officer .
Effective May 17, 2017, Brody J. Wilson was appointed Vice President, Chief Accounting Officer, Controller, and Treasurer. Mr. Wilson had been previously serving as Chief Financial Officer (interim), Treasurer (interim), Chief Accounting Officer and Controller.
Effective April 28, 2017, Ngoni Murandu resigned as Vice President and Chief Information Officer.
Effective September 18, 2017, James Downing was appointed Vice President and Chief Information Officer.

13. Not Applicable

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Reference Page Number (b)	Current Year End of Quarter/Balance Year (c)	Prior Year End Balance 12/31/2016 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	2,956,728,775	2,829,109,354
3	Construction Work in Progress (107)	200-201	159,923,802	62,264,074
4	TOTAL Utility Plant (Total of lines 2 and 3)	200-201	3,116,652,577	2,891,373,428
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 111, 115)	200-201	(1,302,494,942)	(1,242,990,351)
6	Net Utility Plant (Total of line 4 less 5)	—	1,814,157,635	1,648,383,077
7	Nuclear Fuel (120.1-120.4, 120.6)	—	—	—
8	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	—	—	—
9	Net Nuclear Fuel (Total of line 7 less 8)	—	—	—
10	Net Utility Plant (Total of lines 6 and 9)	—	1,814,157,635	1,648,383,077
11	Utility Plant Adjustments (116)	—	—	—
12	Gas Stored-Base Gas (117.1)	220	18,488,587	14,133,895
13	System Balancing Gas (117.2)	220	—	—
14	Gas Stored in Reservoirs and Pipelines-Noncurrent (117.3)	220	—	—
15	Gas Owned to System Gas (117.4)	220	—	—
16	**OTHER PROPERTY AND INVESTMENTS**			
17	Nonutility Property (121)	204-209	69,119,165	67,258,603
18	(Less) Accum. Prov. for Depreciation and Amortization (122)	219	(18,719,439)	(17,395,661)
19	Investments in Associated Companies (123)	222-223	—	—
20	Investment in Subsidiary Companies (123.1)	224-225	152,179,432	290,518,132
21	(For Cost of Account 123.1, See Footnote Page 224, line 40)	—		
22	Noncurrent Portion of Allowances	—	—	—
23	Other Investments (124)	222-223	52,653,735	54,581,443
24	Sinking Funds (125)	—	—	—
25	Depreciation Fund (126)	—	—	—
26	Amortization Fund - Federal (127)	—	—	—
27	Other Special Funds (128)	—	—	—
28	Long-Term Portion of Derivative Assets (175)	—	1,306,000	3,265,000
29	Long-Term Portion of Derivative Assets - Hedges (176)	—	—	—
30	TOTAL Other Property and Investments (Total of lines 17-20, 22-29)	—	256,538,893	398,227,517
31	**CURRENT AND ACCRUED ASSETS**			
32	Cash (131)	—	700,753	1,056,799
33	Special Deposits (132-134)	—	1,930,838	1,910,852
34	Working Funds (135)	—	210,200	185,600
35	Temporary Cash Investments (136)	222-223	2,574,132	3,536,921
36	Notes Receivable (141)	—	—	—
37	Customer Accounts Receivable (142)	—	58,685,488	60,578,953
38	Other Accounts Receivable (143)	—	6,242,775	2,666,067
39	(Less) Accum. Prov. for Uncollectible Accounts-Credit (144)	—	(955,630)	(1,290,276)
40	Notes Receivable from Associated Companies (145)	—	—	—
41	Accounts Receivable from Associated Companies (146)	—	223,899	207,935
42	Fuel Stock (151)	—	—	—
43	Fuel Stock Expense Undistributed (152)	—	—	—

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Reference Page Number (b)	Current Year End of Quarter/Balance Year (c)	Prior Year End Balance 12/31/2016 (d)
44	Residuals (Elec) and Extracted Products (Gas) (153)	—	—	—
45	Plant Material and Operating Supplies (154)	—	10,064,217	10,102,594
46	Merchandise (155)	—	863,669	924,116
47	Other Material and Supplies (156)	—	—	—
48	Nuclear Materials Held for Sale (157)	—	—	—
49	Allowances (158.1 and 158.2)	—	—	—
50	(Less) Noncurrent Portion of Allowances	—	—	—
51	Stores Expenses Undistributed (163)	—	—	—
52	Gas Stored Underground - Current (164.1)	220	32,907,852	38,746,875
53	Liq. Natural Gas Stored and Held for Processing (164.2-164.3)	220	3,741,745	3,989,561
54	Prepayments (165)	230	23,958,674	20,449,382
55	Advances for Gas (166-167)	—	—	—
56	Interest and Dividends Receivable (171)	—	—	—
57	Rents Receivable (172)	—	—	—
58	Accrued Utility Revenues (173)	—	62,380,896	64,945,750
59	Miscellaneous Current and Accrued Assets (174)	—	2,108,594	—
60	Derivative Instrument Assets (175)	—	3,041,000	20,426,000
61	(Less) Long-Term Portion of Derivative Instrument Assets (175)	—	(1,306,000)	(3,265,000)
62	Derivative Instrument Assets - Hedges (176)	—	—	(130,000)
63	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176)	—	—	—
64	TOTAL Current and Accrued Assets (Total of lines 32 thru 63)	—	207,373,102	225,042,129
65	**DEFERRED DEBITS**			
66	Unamortized Debt Expense (181)	259	7,172,109	7,915,836
67	Extraordinary Property Losses (182.1)	230	—	—
68	Unrecovered Plant and Regulatory Study Costs (182.2)	230	—	—
69	Other Regulatory Assets (182.3)	232	22,208,524	43,047,984
70	Prelim. Survey and Investigation Charges (Electric) (183)	—	—	—
71	Prelim. Survey and Invest. Charges (Gas) (183.1, 183.2)	—	351,235	15,080
72	Clearing Accounts (184)	—	237,192	—
73	Temporary Facilities (185)	—	—	—
74	Miscellaneous Deferred Debits (186) (See Note 1)	233	379,132,163	348,569,715
75	Def. Losses from Disposition of Utility Plant (187)	—	—	—
76	Research, Devel. and Demonstration Expend. (188)	—	—	—
77	Unamortized Loss on Reacquired Debt (189)	260	2,117,564	2,473,832
78	Accumulated Deferred Income Taxes (190)	234-235	—	—
79	Unrecovered Purchased Gas Costs (191)	—	(19,277,807)	(2,156,449)
80	Total Deferred Debits (Total of lines 66 thru 79)		391,940,980	399,865,998
81	Total Assets and Other Debits (Total of lines 10-15, 30, 64,and 80)		2,688,499,197	2,685,652,616

Note 1: Prior period balance has been revised to reclassify North Mist COH Regulatory Liability.

Name of Respondent	This Report is:	Date of Report	Year of Report
	(1) ☒ An Original	(Mo, Da, Yr)	
Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Reference Page Number (b)	Current Year End of Quarter/Balance Year (c)	Prior Year End Balance 12/31/2016 (d)
1	**PROPRIETARY CAPITAL**			
2	Common Stock Issued (201)	250-251	451,282,098	447,633,104
3	Preferred Stock Issued (204)	250-251	—	—
4	Capital Stock Subscribed (202, 205)	252	—	—
5	Stock Liability for Conversion (203, 206)	252	—	—
6	Premium on Capital Stock (207)	252	—	—
7	Other Paid-In Capital (208-211)	253	1,649,864	1,649,864
8	Installments Received on Capital Stock (212)	252	51,283	24,333
9	(Less) Discount on Capital Stock (213)	254	—	—
10	(Less) Capital Stock Expense (214)	254	(4,118,163)	(4,120,800)
11	Retained Earnings (215, 215.1, 216)	118-119	472,303,081	453,862,896
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	(167,041,082)	(39,698,388)
13	(Less) Reacquired Capital Stock (217)	250-251	—	—
14	Accumulated Other Comprehensive Income (219)	117	(8,437,839)	(6,950,693)
15	TOTAL Proprietary Capital (Total of lines 2 thru 14)	—	745,689,242	852,400,316
16	**LONG-TERM DEBT**			
17	Bonds (221)	256-257	786,700,000	726,700,000
18	(Less) Reacquired Bonds (222)	256-257	—	—
19	Advances from Associated Companies (223)	256-257	—	—
20	Other Long-Term Debt (224)	256-257	—	—
21	Unamortized Premium on Long-Term Debt (225)	258-259	—	—
22	(Less) Unamortized Discount on Long-Term Debt-Dr. (226)	258-259	—	—
23	(Less) Current Portion of Long-Term Debt	256	(97,000,000)	(40,000,000)
24	TOTAL Long-Term Debt (Total of lines 17 thru 23)	256	689,700,000	686,700,000
25	**OTHER NONCURRENT LIABILITIES**			
26	Obligations Under Capital Leases - Noncurrent (227)	—	—	1,302
27	Accumulated Provision for Property Insurance (228.1)	—	154,000	214,000
28	Accumulated Provision for Injuries and Damages (228.2)	—	110,501,943	105,581,286
29	Accumulated Provision for Pensions and Benefits (228.3)	—	244,476,672	246,639,501
30	Accumulated Miscellaneous Operating Provisions (228.4)	—	—	—
31	Accumulated Provision for Rate Refunds (229)	—	—	—

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Reference Page Number (b)	Current Year End of Quarter/Balance Year (c)	Prior Year End Balance 12/31/2016 (d)
32	Long-Term Portion of Derivative Instrument Liabilities	—	4,649,000	913,000
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges	—	—	—
34	Asset Retirement Obligations (230)	—	—	—
35	TOTAL Other Noncurrent Liabilities (Total of lines 26 thru 34)	—	359,781,615	353,349,089
36	**CURRENT AND ACCRUED LIABILITIES**			
37	Current Portion of Long-term Debt	256	97,000,000	40,000,000
38	Notes Payable (231)	—	54,199,996	53,300,000
39	Accounts Payable (232)	—	108,414,210	83,472,534
40	Notes Payable to Associated Companies (233)	—	—	—
41	Accounts Payable to Associated Companies (234)	—	22,115,481	9,635,034
42	Customer Deposits (235)	—	5,087,361	5,538,638
43	Taxes Accrued (236)	262-263	18,843,587	12,114,133
44	Interest Accrued (237)	—	6,773,318	5,965,876
45	Dividends Declared (238)	—	—	—
46	Matured Long-Term Debt (239)	—	—	—
47	Matured Interest (240)	—	—	—
48	Tax Collections Payable (241)	—	5,779,961	4,885,736
49	Miscellaneous Current and Accrued Liabilities (242)	268	26,390,275	21,861,114
50	Obligations Under Capital Leases-Current (243)	—	—	(1,302)
51	Derivative Instrument Liabilities (244)	—	23,371,000	2,098,000
52	(Less) Long-Term Portion of Derivative Instrument Liabilities	—	(4,649,000)	(913,000)
53	Derivative Instrument Liabilities - Hedges (245)	—	—	130,000
54	(Less) Long-Term Portion of Derivative Instrument Liabilities - Hedges	—	—	—
55	TOTAL Current and Accrued Liabilities (Total of lines 37 thru 54)	—	363,326,189	238,086,763
56	**DEFERRED CREDITS**			
57	Customer Advances for Construction (252)	—	3,965,149	3,740,828
58	Accumulated Deferred Investment Tax Credits (255)	—	2	3,983
59	Deferred Gains from Disposition of Utility Plant (256)	—	—	—
60	Other Deferred Credits (253)	269	7,323,027	7,142,848
61	Other Regulatory Liabilities (254) (See Note 1)	278	230,410,020	32,969,672
62	Unamortized Gain on Reacquired Debt (257)	260	—	—
63	Accumulated Deferred Income Taxes - Accelerated Amortization (281)	—	—	—
64	Accumulated Deferred Income Taxes - Other Property (282)	—	—	—
65	Accumulated Deferred Income Taxes - Other (283)	276-277	288,303,953	511,259,117
66	TOTAL Deferred Credits (Total of lines 57 thru 65)	—	530,002,151	555,116,448
67	TOTAL Liabilities and Other Credits (Total of lines 15, 24, 35, 55 and 66)	—	2,688,499,197	2,685,652,616

Note 1: Prior period balance has been revised to reclassify North Mist COH Regulatory Liability.

STATEMENT OF INCOME FOR THE YEAR

1. Report amounts for accounts 412 and 413, Revenue and Expenses from Utility Plant Leased to Others, in another utility column (i,j) in a similar manner to a utility department. Spread the amounts(s) over lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.

2. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.

3. Report data for lines 8, 10, and 11 for Natural Gas companies using accounts 404.1, 404.2, 404.3, 407.1, and 407.2.

Line No.	Account (a)	(Ref.) Page No. (b)	Total Current Year (in dollars) (c)	Total Previous Year (in dollars) (d)	Current Three Months Ended Quarterly Only No Fourth Quarter (e)	Prior Three Months Ended Quarterly Only No Fourth Quarter (f)
1	**UTILITY OPERATING INCOME**					
2	Gas Operating Revenues (400)	300-301	752,010,969	667,587,076		
3	Operating Expenses	—				
4	Operation Expenses (401)	320-325	460,647,011	385,537,739		
5	Maintenance Expenses (402)	320-325	16,002,925	16,696,620		
6	Depreciation Expense (403)	336-338	79,733,795	76,288,699		
7	Depreciation Expense for Asset Retirement Costs (403.1)	—	—	—		
8	Amort. & Depl. of Utility Plant (404-405)	336-338	—	—		
9	Amort. of Utility Plant Acu. Adjustment (406)	336-338	—	—		
10	Amort of Prop. Losses, Unrecovered Plant and Regulatory Study Costs (407.1)	—	—	—		
11	Amort. of Conversion Expenses (407.2)	—	—	—		
12	Regulatory Debits (407.3)	—	15,291,409	13,298,002		
13	(Less) Regulatory Credits (407.4)	—	—	—		
14	Taxes Other Than Income Taxes (408.1)	262-263	49,004,406	45,675,819		
15	Income Taxes - Federal (409.1)	262-263	16,162,896	12,960,657		
16	Income Taxes - Other (409.1)	262-263	5,290,475	2,812,242		
17	Provision for Deferred Income Taxes (410.1)	276-277	58,229,567	45,245,865		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	276-277	38,750,782	21,966,966		
19	Investment Tax Credit Adj. - Net (411.4)	—	(3,981)	(43,583)		
20	(Less) Gains from Disp. of Utility Plant (411.6)	—	—	—		
21	Losses from Disp. of Utility Plant (411.7)	—	—	—		
22	(Less) Gains from Disposition of Allowances (411.8)	—	—	—		
23	Losses from Disposition of Allowances (411.9)	—	—	—		
24	Accretion Expense (411.10)	—	—	—		
25	TOTAL Utility Operating Expenses (Total of lines 4 thru 24)	—	661,607,721	576,505,094		
26	Net Utility Operating income (Enter Total of line 2 less 25) (Carry forward to page 116, line 27)	—	90,403,248	91,081,982		

Name of Respondent	This Report is:	Date of Report	Year of Report
	(1) ☒ An Original	(Mo, Da, Yr)	
Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

STATEMENT OF INCOME FOR THE YEAR

4. Explain in a footnote if the previous year's figures are different from that reported in prior reports.

5. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles, line 2 to 23 and report the information in the blank space on page 122 or in a supplemental statement.

Elec. Utility Total Current Year (in dollars) (g)	Elec. Utility Total Previous Year (in dollars) (h)	Gas Utility Total Current Year (in dollars) (i)	Gas Utility Total Previous Year (in dollars) (j)	Other Utility Total Current Year (in dollars) (k)	Other Utility Total Previous Year (in dollars) (l)	Line No.
						1
		752,010,969	667,587,076			2
						3
		460,647,011	385,537,739			4
		16,002,925	16,696,620			5
		79,733,795	76,288,699			6
		—	—			7
		—	—			8
		—	—			9
		—	—			10
		—	—			11
		15,291,409	13,298,002			12
		—	—			13
		49,004,406	45,675,819			14
		16,162,896	12,960,657			15
		5,290,475	2,812,242			16
		58,229,567	45,245,865			17
		38,750,782	21,966,966			18
		(3,981)	(43,583)			19
		—	—			20
		—	—			21
		—	—			22
		—	—			23
		—	—			24
		661,607,721	576,505,094			25
		90,403,248	91,081,982			26

STATEMENT OF INCOME (Continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Total Current Year To Date Balance for Quarter/Year (c)	Total Current Year To Date Balance for Quarter/Year (d)	Current Three Months Ended Quarterly Only No Fourth Quarter (e)	Prior Three Months Ended Quarterly Only No Fourth Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)	—	90,403,248	91,081,982		
28	Other Income and Deductions					
29	Other Income					
30	Nonutility Operating Income					
31	Revenues From Merch, Jobbing and Contract Work (415)	—	5,641,506	5,164,002		
32	(Less) Costs and Exp. of Merch, Job & Contract Work (416)	—	5,492,608	5,073,484		
33	Revenues From Nonutility Operations (417)	—	29,937,459	30,226,415		
34	(Less) Expenses of Nonutility Operations (417.1)	—	15,525,969	14,979,583		
35	Nonoperating Rental Income (418)	—	430,848	467,099		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	(127,342,693)	(3,939,573)		
37	Interest and Dividend Income (419)	—	3,932,693	776,187		
38	Allow. for Other Funds Used During Constr (419.1)	—	2,601,368	—		
39	Miscellaneous Nonoperating Income (421)	—	42,438	48,406		
40	Gain on disposition of Property (421.1)	—	—	—		
41	TOTAL Other Income (Total of lines 31 thru 40)	—	(105,774,958)	12,689,469		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)	—	—	—		
44	Miscellaneous Amortization (425)	—	—	—		
45	Donations (426.1)	340	1,020,825	1,166,216		
46	Life Insurance (426.2)	—	(2,492,693)	(1,696,962)		
47	Penalties (426.3)	—	400	5		
48	Expenditures for Certain Civic, Political and Related Activities (426.4)	—	1,135,662	1,272,927		
49	Other Deductions (426.5)	—	58,035	236,764		
50	TOTAL Other Income Deductions (Total of Lines 43 thru 49)	340	(277,771)	978,950		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	681,501	655,905		
53	Income Taxes - Federal (409.2)	262-263	3,140,977	2,498,076		
54	Income Taxes - Other (409.2)	262-263	665,079	490,601		
55	Provision for Deferred Inc. Taxes (410.2)	272-277	(2,415,299)	2,453,227		
56	(Less) Provision for Deferred Inc. Taxes - Cr. (411.2)	272-277	182,373	843,924		
57	Investment Tax Credit Adj. - Net (411.5)	—	—	—		
58	(Less) Investment Tax Credits (420)	—	—	—		
59	TOTAL Taxes on Other Inc. and Ded. (Total of 52 thru 58)	—	1,889,885	5,253,885		
60	Net Other Income and Deductions (Total of Lines 41, 50, 59)	—	(107,387,072)	6,456,634		
61	Interest Charges					
62	Interest on Long-Term Debt (427)	256-257	36,808,658	34,508,090		
63	Amortization of Debt Disc. and Expense (428)	258-259	1,660,650	1,314,276		
64	Amortization of Loss on Reacquired Debt (428.1)	260	356,268	356,268		
65	(Less) Amort. of Premium on Debt - Credit (429)	256-257	—	—		
66	(Less) Amortization of Gain on Reacquired Debt - Credit (429.1)	—	—	—		
67	Interest on Debt to Assoc. Companies (430)	340	—	—		
68	Other Interest Expense (431)	—	1,299,074	2,421,401		
69	(Less) Allow. for Borrowed Funds Used During Const.-Cr. (432)	—	2,494,702	463,904		

Name of Respondent	This Report is:	Date of Report	Year of Report
Northwest Natural Gas Company	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	December 31, 2017

70	Net Interest Charges (Total of lines 62 thru 69) (See note 1 below)	—	37,629,948	38,136,131		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)	—	(54,613,772)	59,402,485		
72	Extraordinary Items					
73	Extraordinary Income (434)	—	—	—		
74	(Less) Extraordinary Deductions (435)	—	—	—		
75	Net Extraordinary Items (Total of line 73 less 74)	—	—	—		
76	Income Taxes - Federal and Other (409.3)	262-263	—	—		
77	Extraordinary Items After Taxes (Total of line 75 less line 76)	—	—	—		
78	Net Income (Total of lines 71 and 77)	—	(54,613,772)	59,402,485		

Note 1

Line 70 detail		
Utility interest expense	36,683,366	37,130,516
Non-Utility interest expense	946,582	1,005,615
	37,629,948	38,136,131

Note 2

Accounting standards allow for the capitalization of all or part of an incurred cost that would otherwise be charged to expense if a regulator provides orders that create probable recovery of past costs through future revenues. NW Natural Gas Company accrues interest as specified by regulatory order on certain regulatory balances at our authorized rate of return (ROR). This ROR includes both a debt and equity component, which we are allowed to recover from customers in the form of a carrying cost on regulatory deferred account balances. The equity component of our ROR is not an incurred cost that would otherwise be charged to expense, and therefore is not capitalized and recognized as income for financial reporting purposes. This leads to a difference in reported Net Income between the FERC Form 2 and the Form 10-K filed with the Securities & Exchange Commission (SEC).

Name of Respondent	This Report is:	Date of Report	Year of Report
	(1) ☒ An Original	(Mo, Da, Yr)	
Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

Statement of Accumulated Comprehensive Income and Hedging Activities

1. Report the amounts of accumulated other comprehensive income items, on a net-of-tax basis, where appropriate.
2. Report the amounts of other categories of other cash flow hedges.
3. For each category of hedges that have been accounted for as "fair value hedges", report the accounts affected and the related amounts in a footnote.

Line No.	Item (a)	Current Year Amount (b)
1	Beginning AOCI Balance	(6,950,693)
2	Unrealized Gains/losses on available-for-sale securities, net of tax	—
3	Pension liability adjustment, net of tax	(2,059,566)
4	Amortization of pension liabilities, net of tax	572,420
5	Foreign currency hedges, net of tax	—
6	Change in unrealized loss from hedging, net of tax	—
7	Cash flow hedges, net of tax	—
8	Other adjustments, net of tax	—
9	Ending Balance of AOCI	(8,437,839)

STATEMENT OF RETAINED EARNINGS FOR THE YEAR

1. Report all changes in appropriated retained earnings, unappropriated retained earnings, and unappropriated undistributed subsidiary earnings for the year.

2. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436-439 inclusive). Show the contra primary account affected in column (b).

3. State the purpose and amount for each reservation or appropriation of retained earnings.

4. List first Account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items, in that order.

5. Show dividends for each class and series of capital stock.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Year Amount (c)	Previous Year Amount (d)
	UNAPPROPRIATED RETAINED EARNINGS			
1	Balance - Beginning of Year		453,862,896	442,145,578
2	Changes (Identify by prescribed retained earnings accounts)			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6	Balance Transferred from Income (Account 433 less Account 418.1)		72,728,921	63,342,058
7	Appropriations of Retained Earnings (Account 436)			
8				
9	Dividends Declared - Preferred Stock (Account 437))			
10				
11	Dividends Declared - Common Stock (Account 438)			
12	Common Stock - Cash Dividends		(53,957,310)	(51,508,472)
12.1	Common Stock - Stock Dividends		—	—
12.2	TOTAL Dividends Declared - Common Stock (Account 438) (Total of lines 12.1 thru 12.2)		(53,957,310)	(51,508,472)
13	Transfers from Acct. 216.1, Unappropriated Undistributed Subsidiary Earnings		—	—
13.1	Other Changes (Explain) (see Note 1 below)		(331,426)	(116,268)
14	Balance - End of Year (Total of lines 1, 4, 5, 6, 8, 10, 12, and 13)		472,303,081	453,862,896
15	APPROPRIATED RETAINED EARNINGS (Account 215)			
16	TOTAL Appropriated Retained Earnings (Account 215)		—	—
17	APPROPRIATED RETAINED EARNINGS - AMORTIZATION RESERVE, FEDERAL (Account 215.1)			
18	TOTAL Appropriated Retained Earnings - Amortization Reserve,		—	—
19	TOTAL Appropriated Retained Earnings (Accounts 215, 215.1)		—	—
20	TOTAL Retained Earnings (Account 215, 215.1, 216)		472,303,081	453,862,896
21	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (ACCOUNT 216.1)			
	Report only on an Annual Basis No Quarterly			
22	Balance - Beginning of Year (Debit or Credit)		(39,698,388)	(35,758,812)
23	Equity in Earnings for Year (Credit) (Account 418.1)		(127,342,693)	(3,939,573)
24	(Less) Dividends Received (Debit)		—	—
25	Other Changes (Explain)		(1)	(3)
26	Balance - End of year (Total of lines 20 thru 23)		(167,041,082)	(39,698,388)

Note 1: Other Changes include $331k of non-cash dividend adjustments to the LTIP awards and immaterial round differences.

Name of Respondent	This Report is:	Date of Report	Year of Report
Northwest Natural Gas Company	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	December 31, 2017

STATEMENT OF CASH FLOWS

1. Codes to be used: (a) Net Proceeds or Payments;(b) Bonds, debentures and other long-term debt;(c) Include commercial paper; (d) Identify separately such items as investments, fixed assets, intangibles,etc.

2. Information about noncash investing and financing activities should be provided on page 122. Provide also on page 122 a reconciliation between "Cash and Cash Equivalents at End of Year" with related amounts on the balance sheet.

3. Operating Activities-Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show on page 122 the amounts of interest paid (net of amounts capitalized)and income taxes paid.

4. Investing Activities: Include at Other (line 25) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed on page 122. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	DESCRIPTION (See Instructions for Explanation of Codes) (a)	Current Year Amount (b)	Previous Year Amount (c)
1	Net Cash Flow from Operating Activities:		
2	Net Income (Line 78(c) on page 116)	(54,613,772)	59,402,485
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	81,023,524	77,575,014
5	Amortization	1,660,650	2,018,823
5.01	FAS 109 Deferred Taxes	(20,839,460)	(4,378,568)
5.02	FAS 109 Regulatory Asset	20,839,460	4,378,568
6	Deferred Income Taxes (Net)	(27,125,160)	29,621,886
7	Investment Tax Credit Adjustments (Net)	(3,981)	(43,584)
8	Net (Increase) Decrease in Receivables	2,386,549	4,348,054
9	Net (Increase) Decrease in Inventory	6,086,839	16,474,545
10	Net (Increase) Decrease in Allowances Inventory	—	—
11	Net Increase (Decrease) in Payables and Accrued Expenses	19,862,743	26,855,858
12	Minimum Pension Liability Adjustment	(1,487,146)	211,509
13	Unrealized (gain)/loss from price risk management activities	60,024,108	(21,357,374)
14	(Less) Allowance for Other Funds Used During Construction	(5,096,070)	(463,904)
15	(Less) Undistributed Earnings from Subsidiary Companies	127,342,693	3,939,573
16	Other: Net (Increase) Decrease in Unbilled Revenues	2,564,854	(6,958,265)
16.01	Deferred Debits - Net	(28,867,092)	577,829
16.02	Net (Increase) Decrease in Other Current Assets & Liab.	(784,145)	20,639,561
16.03	Other - Noncurrent Liab., Deferred Credits, & Other Invest.	1,274,241	(16,916,288)
16.04	Unearned Compensation	28,887	5,486,742
17	Net Cash Provided by (Used in) Operating Activities		
18	(Total of lines 2 thru 16.04)	184,277,722	201,412,464
19			
20	Cash Flows from Investment Activities:		
21	Construction and Acquisition of Plant (including land):		
22	Gross Additions to Utility Plant (less nuclear fuel)	(205,836,587)	(131,300,138)
23	Gross Additions to Nuclear Fuel	—	—
24	Gross Additions to Common Utility Plant	—	—
25	Gross Additions to Nonutility Plant	(1,427,338)	(283,831)
26	(Less) Allowance for Other Funds Used During Construction	5,096,070	463,904
27	Other	(3,959,706)	535,768
28	Cash Outflows for Plant (Total of lines 22 thru 27)	(206,127,561)	(130,584,297)
29			
30	Acquisition of Other Noncurrent Assets (d)	—	—
31	Proceeds from Disposal of Noncurrent Assets (d)	—	1,002
32			
33	Investments in & Advances to Assoc. & Sub. Companies	—	—
34	Contributions & Advances from Assoc. & Sub. Companies	10,996,007	11,743,620
35	Disposition of Investments in (and Advances to)		
36	Associated and Subsidiary Companies	—	—
37			
38	Purchase of Investment Securities (a)	—	—
39	Proceeds from Sales of Investment Securities (a)	—	—

STATEMENT OF CASH FLOWS (Continued)

Line No.	DESCRIPTION (See Instructions for Explanation of Codes) (a)	Current Year Amount (b)	Previous Year Amount (c)
40	Loans Made or Purchased	—	—
41	Collections on Loans	—	—
42			
43	Net (Increase) Decrease in Receivables	—	—
44	Net (Increase) Decrease in Inventory	—	—
45	Net (Increase) Decrease in Allowances Held for Speculation	—	—
46	Net Increase (Decrease) in Payables and Accrued Expenses	—	—
47		—	—
48	Net Cash Provided by (Used in) Investing Activities		
49	(Total of lines 28 thru 47)	(195,131,554)	(118,839,675)
50			
51	Cash Flows from Financing Activities:		
52	Proceeds from Issuance of:		
53	Long-Term Debt (b)	100,000,000	150,000,000
54	Preferred Stock	—	—
55	Common Stock	4,821,851	60,122,196
56	Other: Capital Leases	—	—
57	Net Increase in Short-Term Debt (c)	899,996	(216,735,306)
58			
59	Cash Provided by Outside Sources (Total of lines 53 thru 58)	105,721,847	(6,613,110)
60			
61	Payments for Retirement of:		
62	Long-Term Debt (b)	(40,000,000)	(25,000,000)
63	Preferred Stock	—	—
64	Common Stock	(2,033,860)	—
65	Other: Capital Leases	(153,731)	(559,256)
66	Net Increase (Decrease) in Short-Term Debt (c)	—	—
67	Capital Stock Expense	2,637	(6,880)
68	Dividends on Preferred Stock	—	—
69	Dividends on Common Stock	(53,957,310)	(51,508,472)
70	Net Cash Provided by (Used in) Financing Activities		
71	(Total of lines 59 thru 69)	9,579,583	(83,687,718)
72			
73	Net Increase (Decrease) in Cash and Cash Equivalents		
74	(Total of lines 18, 49, and 71)	(1,274,249)	(1,114,929)
75			
76	Cash and Cash Equivalents at Beginning of Period	6,690,172	7,805,101
77			
78	Cash and Cash Equivalents at End of Period	5,415,923	6,690,172

Notes to Financial Statements

1. Provide important disclosures regarding the Balance Sheet, Statement of Income for the Year, Statement of Retained Earnings for the Year, and Statement of Cash Flow, or any account thereof. Classify the disclosures according to each financial statement, providing a subheading for each statement except where a disclosure is applicable to more than one statement. The disclosures must be on the same subject matters and in the same level of detail that would be required if the respondent issued general purpose financial statements to the public or shareholders.

2. Furnish details as to any significant contingent assets or liabilities existing at year end, and briefly explain any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or a claim for refund of income taxes of a material amount initiated by the utility. Also, briefly explain any dividends in arrears on cumulative preferred stock.

3. Furnish details on the respondent's pension plans, post-retirement benefits other than pensions (PBOP) plans, and post-employment benefit plans as required by instruction no. 1 and, in addition, disclose for each individual plan the current year's cash contributions. Furnish details on the accounting for the plans and any changes in the method of accounting for them. Include details on the accounting for transition obligations or assets, gains or losses, the amounts deferred and the expected recovery periods. Also, disclose any current year's plan or trust curtailments, terminations, transfers, or reversions of assets. Entities that participate in multiemployer postretirement benefit plans (e.g. parent company sponsored pension plans) disclose in addition to the required disclosures for the consolidated plan, (1) the amount of cost recognized in the respondent's financial statements for each plan for the period presented, and (2) the basis for determining the respondent's share of the total plan costs.

4. Furnish details on the respondent's asset retirement obligations (ARO) as required by instruction no. 1 and, in addition, disclose the amounts recovered through rates to settle such obligations. Identify any mechanism or account in which recovered funds are being placed (i.e. trust funds, insurance policies, surety bonds). Furnish details on the accounting for the asset retirement obligations and any changes in the measurement or method of accounting for the obligations. Include details on the accounting for settlement of the obligations and any gains or losses expected or incurred on the settlement.

5. Provide a list of all environmental credits received during the reporting period.

6. Provide a summary of revenues and expenses for each tracked cost and special surcharge.

7. Where Account 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these item. See General Instruction 17 of the Uniform System of Accounts.

8. Explain concisely any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.

9. Disclose details on any significant financial changes during the reporting year to the respondent or the respondent's consolidated group that directly affect the respondent's gas pipeline operations, including: sales, transfers or mergers of affiliates, investments in new partnerships, sales of gas pipeline facilities or the sale of ownership interests in the gas pipeline to limited partnerships, investments in related industries (i.e., production, gathering), major pipeline investments, acquisitions by the parent corporation(s), and distributions of capital.

10. Explain concisely unsettled rate proceedings where a contingency exists such that the company may need to refund a material amount to the utility's customers or that the utility may receive a material refund with respect to power or gas purchases. State for each year affected the gross revenues or costs to which the contingency relates and the tax effects and explain the major factors that affect the rights of the utility to retain such revenues or to recover amounts paid with respect to power and gas purchases.

11. Explain concisely significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purchases, and summarize the adjustments made to balance sheet, income, and expense accounts.

12. Explain concisely only those significant changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also give the approximate dollar effect of such changes.

13. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.

14. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However where material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.

15. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.

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NORTHWEST NATURAL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION AND PRINCIPLES OF CONSOLIDATION

The accompanying consolidated financial statements represent the consolidated results of Northwest Natural Gas Company (NW Natural or the Company) and all companies we directly or indirectly control, either through majority ownership or otherwise. We have two core businesses: our regulated local gas distribution business, referred to as the utility segment, which serves residential, commercial, and industrial customers in Oregon and southwest Washington; and our gas storage businesses, referred to as the gas storage segment, which provides storage services for utilities, gas marketers, electric generators, and large industrial users from facilities located in Oregon and California. In addition, we have investments and other non-utility activities we aggregate and report as other.

Our core utility business assets and operating activities are largely included in the parent company, NW Natural. Our direct and indirect wholly-owned subsidiaries include NW Natural Energy, LLC (NWN Energy), NW Natural Gas Storage, LLC (NWN Gas Storage), Gill Ranch Storage, LLC (Gill Ranch), NNG Financial Corporation (NNG Financial), Northwest Energy Corporation (Energy Corp), Northwest Natural Water Company (NWN Water), FWC Merger Sub, Inc., and NWN Gas Reserves LLC (NWN Gas Reserves). Investments in corporate joint ventures and partnerships we do not directly or indirectly control, and for which we are not the primary beneficiary, include NWN Financial's investment in Kelso-Beaver Pipeline and NWN Energy's investment in Trail West Holdings, LLC (TWH), which is accounted for under the equity method. NW Natural and its affiliated companies are collectively referred to herein as NW Natural. The consolidated financial statements are presented after elimination of all intercompany balances and transactions. In this report, the term “utility” is used to describe our regulated gas distribution business, and the term “non-utility” is used to describe our gas storage businesses and other non-utility investments and business activities.

Certain prior year balances in our consolidated financial statements and notes have been reclassified to conform with the current presentation. These reclassifications had no effect on our prior year’s consolidated results of operations, financial condition, or cash flows.

2. SIGNIFICANT ACCOUNTING POLICIES

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles in the United States of America (GAAP) requires management to make estimates and assumptions that affect reported amounts in the consolidated financial statements and accompanying notes. Actual amounts could differ from those estimates, and changes would most likely be reported in future periods. Management believes the estimates and assumptions used are reasonable.

Industry Regulation

Our principal businesses are the distribution of natural gas, which is regulated by the OPUC and WUTC, and natural gas storage services, which are regulated by either the FERC or the CPUC, and to a certain extent by the OPUC and WUTC. Accounting records and practices of our regulated businesses conform to the requirements and uniform system of accounts prescribed by these regulatory authorities in accordance with U.S. GAAP. Our businesses regulated by the OPUC, WUTC, and FERC earn a reasonable return on invested capital from approved cost-based rates, while our business regulated by the CPUC earns a return to the extent we are able to charge competitive prices above our costs (i.e. market-based rates).

In applying regulatory accounting principles, we capitalize or defer certain costs and revenues as regulatory assets and liabilities pursuant to orders of the OPUC or WUTC, which provide for the recovery of revenues or expenses from, or refunds to, utility customers in future periods, including a return or a carrying charge in certain cases.

At December 31, the amounts deferred as regulatory assets and liabilities were as follows:

	Regulatory Assets	
In thousands	2017	2016
Current:		
Unrealized loss on derivatives(1)	$ 18,712	$ 1,315
Gas costs	154	6,830
Environmental costs(2)	6,198	9,989
Decoupling(3)	11,227	13,067
Income taxes	2,218	4,378
Other(4)	7,272	6,783
Total current	$ 45,781	$ 42,362
Non-current:		
Unrealized loss on derivatives(1)	$ 4,649	$ 913
Pension balancing(5)	60,383	50,863
Income taxes	19,991	38,670
Pension and other postretirement benefit liabilities	179,824	183,035
Environmental costs(2)	72,128	63,970
Gas costs	84	89
Decoupling(3)	3,970	5,860
Other(4)	15,579	14,130
Total non-current	$ 356,608	$ 357,530

In thousands	Regulatory Liabilities 2017	2016
Current:		
Gas costs	$ 14,886	$ 8,054
Unrealized gain on derivatives[(1)]	1,674	16,624
Decoupling[(3)]	322	—
Other[(4)]	17,131	15,612
Total current	$ 34,013	$ 40,290
Non-current:		
Gas costs	$ 4,630	$ 1,021
Unrealized gain on derivatives[(1)]	1,306	3,265
Decoupling[(3)]	957	—
Income taxes	213,306	—
Accrued asset removal costs[(6)]	360,929	341,107
Other[(4)]	4,965	3,926
Total non-current	$ 586,093	$ 349,319

(1) Unrealized gains or losses on derivatives are non-cash items and, therefore, do not earn a rate of return or a carrying charge. These amounts are recoverable through utility rates as part of the annual Purchased Gas Adjustment (PGA) mechanism when realized at settlement.

(2) Refer to footnote (3) per the Deferred Regulatory Asset table in Note 15 for a description of environmental costs.

(3) This deferral represents the margin adjustment resulting from differences between actual and expected volumes.

(4) These balances primarily consist of deferrals and amortizations under approved regulatory mechanisms. The accounts being amortized typically earn a rate of return or carrying charge.

(5) Refer to footnote (1) of the Net Periodic Benefit Cost table per Note 8 for information regarding the deferral of pension expenses.

(6) Estimated costs of removal on certain regulated properties are collected through rates. See "Accounting Policies—*Plant, Property, and Accrued Asset Removal Costs*" below.

The amortization period for our regulatory assets and liabilities ranges from less than one year to an indeterminable period. Our regulatory deferrals for gas costs payable are generally amortized over 12 months beginning each November 1 following the gas contract year during which the deferred gas costs are recorded. Similarly, most of our other regulatory deferred accounts are amortized over 12 months. However, certain regulatory account balances, such as income taxes, environmental costs, pension liabilities, and accrued asset removal costs, are large and tend to be amortized over longer periods once we have agreed upon an amortization period with the respective regulatory agency.

We believe all costs incurred and deferred at December 31, 2017 are prudent. We annually review all regulatory assets and liabilities for recoverability and more often if circumstances warrant. If we should determine that all or a portion of these regulatory assets or liabilities no longer meet the criteria for continued application of regulatory accounting, we would be required to write-off the net unrecoverable balances in the period such determination is made.

Environmental Regulatory Accounting

See Note 15 for information about our SRRM and OPUC orders regarding implementation.

New Accounting Standards

We consider the applicability and impact of all accounting standards updates (ASUs) issued by the Financial Accounting Standards Board (FASB). Accounting standards updates not listed below were assessed and determined to be either not applicable or are expected to have minimal impact on our consolidated financial position or results of operations.

Recently Issued Accounting Pronouncements

DERIVATIVES AND HEDGING. On August 28, 2017, the FASB issued ASU 2017-12, "Derivatives and Hedging: Targeted Improvements to Accounting for Hedging Activities." The purpose of the amendment is to more closely align hedge accounting with companies' risk management strategies. The ASU amends the accounting for risk component hedging, the hedged item in fair value hedges of interest rate risk, and amounts excluded from the assessment of hedge effectiveness. The guidance also amends the recognition and presentation of the effect of hedging instruments and includes other simplifications of hedge accounting. The amendments in this update are effective for us beginning January 1, 2019. Early adoption is permitted. The amended presentation and disclosure guidance is required prospectively. We are currently assessing the effect of this standard on our financial statements and disclosures.

STOCK COMPENSATION. On May 10, 2017, the FASB issued ASU 2017-09, "Stock Compensation - Scope of Modification Accounting." The purpose of the amendment is to provide clarity, reduce diversity in practice and reduce the cost and complexity when applying the guidance in ASC 718, related to a change to the terms or conditions of a share-based payment award. The ASU amends the scope of modification accounting for share-based payment arrangements and provides guidance on the types of changes to the terms or conditions of share-based payment awards to which an entity would be required to apply modification accounting under ASC 718. Specifically, an entity would not apply modification accounting if the fair value, vesting conditions, and classification of the awards are the same immediately before and after the modification. The amendments in this update are effective for us beginning January 1, 2018. The amendments in this update should be applied prospectively to an award modified on or after the adoption date. We do not expect this standard to materially affect our financial statements and disclosures.

RETIREMENT BENEFITS. On March 10, 2017, the FASB issued ASU 2017-07, "Improving the Presentation of Net Periodic Pension Cost and Net Periodic Post Retirement Benefit Cost." The ASU requires entities to disaggregate current service cost from the other components of net periodic benefit cost and present it with other current compensation costs for related employees in the income statement and to present the other components elsewhere in the income statement and outside of income from operations if that subtotal is presented. Only the service cost component of the net periodic benefit cost is eligible for capitalization. The amendments in this update are effective for us beginning January 1, 2018. Upon adoption, the ASU requires that changes to the income statement presentation of net periodic benefit cost be applied retrospectively, while changes to amounts capitalized must be applied prospectively. On December 28, 2017, the FERC issued Docket AI18-1-000 stating that it will allow entities to change their capitalization policy for regulatory accounting and reporting purposes to be consistent with the new US GAAP requirements. This change will be allowed as a one-time policy election upon adoption of the guidance. We have elected to adopt the new ASU for FERC regulatory accounting and reporting purposes. We anticipate that this adoption will reduce amounts capitalized to plant. However, this reduction will be largely offset by deferrals to our pension regulatory balancing mechanism, and therefore, we do not expect this standard to materially affect our financial position.

STATEMENT OF CASH FLOWS. On August 26, 2016, the FASB issued ASU 2016-15, "Classification of Certain Cash Receipts and Cash Payments." The ASU adds guidance pertaining to the classification of certain cash receipts and payments on the statement of cash flows. The purpose of the amendment is to clarify issues that have been creating diversity in practice, including the classification of proceeds from the settlement of insurance claims and proceeds from the settlement of corporate-owned life insurance policies. The amendments in this standard are effective for us beginning January 1, 2018. We do not expect this standard to materially affect our financial statements and disclosures.

LEASES. On February 25, 2016, the FASB issued ASU 2016-02, "Leases," which revises the existing lease accounting guidance. Pursuant to the new standard, lessees will be required to recognize all leases, including operating leases that are greater than 12 months at lease commencement, on the balance sheet and record corresponding right-of-use assets and lease liabilities. Lessor accounting will remain substantially the same under the new standard. Quantitative and qualitative disclosures are also required for users of the financial statements to have a clear understanding of the nature of our leasing activities. The standard is effective for us beginning January 1, 2019. The new standard must be adopted using a modified retrospective transition and provides for certain practical expedients. On November 29, 2017, the FASB proposed an additional practical expedient that would allow entities to apply the transition requirements on the effective date of the standard.

On January 25, 2018, the FASB issued ASU 2018-01, "Land Easement Practical Expedient for Transition to Topic 842", to address the costs and complexity of applying the transition provisions of the new lease standard to land easements. This ASU provides an optional practical expedient to not evaluate existing or expired land easements that were not previously accounted for as leases under the current lease guidance.

We are evaluating additional amendments reached by the FASB, and we are currently assessing our lease population and material contracts to determine the effect of this standard on our financial statements and disclosures. Refer to Note 14 for our current lease commitments.

FINANCIAL INSTRUMENTS. On January 5, 2016, the FASB issued ASU 2016-01, "Financial Instruments - Overall: Recognition and Measurement of Financial Assets and Financial Liabilities." The ASU enhances the reporting model for financial instruments, which includes amendments to address aspects of recognition, measurement, presentation, and disclosure. The new standard is effective for us beginning January 1, 2018. Any impacts as a result of the implementation of this ASU will be made through a cumulative-effect adjustment to the consolidated balance sheet in the first quarter of 2018. We do not expect this standard to have a material impact to our financial statements and disclosures.

REVENUE RECOGNITION. On May 28, 2014, the FASB issued ASU 2014-09 "Revenue From Contracts with Customers." Subsequently, the FASB issued additional, clarifying amendments to address issues and questions regarding implementation of the new revenue recognition standard. The underlying principle of the guidance requires entities to recognize revenue depicting the transfer of goods or services to customers at amounts the entity is expected to be entitled to in exchange for those goods or services. The ASU also prescribes a five-step approach to revenue recognition: (1) identify the contract(s) with the customer; (2) identify the separate performance obligations in the contract(s); (3) determine the transaction price; (4) allocate the transaction price to separate performance obligations; and (5) recognize revenue when, or as, each performance obligation is satisfied. The guidance also requires additional disclosures, both qualitative and quantitative, regarding the nature, amount, timing and uncertainty of revenue and cash flows. The new requirements prescribe either a full retrospective or modified retrospective adoption method. The new standard is effective for us beginning January 1, 2018, and we have elected to adopt the standard using the modified retrospective approach. We are in the process of updating our accounting policies, processes, systems, and internal controls as a result of implementing the new standard. We have analyzed our revenue streams, material contracts with customers, and the expanded disclosure requirements under the new standard and determined that the standard will not have a material impact on our financial position, net income, or cash flows.

Accounting Policies

Plant, Property, and Accrued Asset Removal Costs

Plant and property are stated at cost, including capitalized labor, materials, and overhead. In accordance with regulatory accounting standards, the cost of acquiring and constructing long-lived plant and property generally includes an allowance for funds used during construction (AFUDC) or capitalized interest. AFUDC represents the regulatory financing cost incurred when debt and equity funds are used for construction (see "*AFUDC*" below). When constructed assets are subject to market-based rates rather than cost-based rates, the financing costs incurred during construction are included in capitalized interest in accordance with U.S. GAAP, not as regulatory financing costs under AFUDC.

In accordance with long-standing regulatory treatment, our depreciation rates consist of three components: one based on the average service life of the asset, a second based on the estimated salvage value of the asset, and a third based on the asset's estimated cost of removal. We collect, through rates, the estimated cost of removal on certain regulated properties through depreciation expense, with a corresponding offset to accumulated depreciation. These removal costs are non-legal obligations as defined by regulatory accounting guidance. Therefore, we have included these costs as non-current regulatory liabilities rather than as accumulated depreciation on our consolidated balance sheets. In the rate setting process, the liability for removal costs is treated as a reduction to the net rate base on which the regulated utility has the opportunity to earn its allowed rate of return.

The costs of utility plant retired or otherwise disposed of are removed from utility plant and charged to accumulated depreciation for recovery or refund through future rates. Gains from the sale of regulated assets are generally deferred and refunded to customers. For non-utility assets, we record a gain or loss upon the disposal of the property, and the gain or loss is recorded in operating income or loss in the consolidated statements of comprehensive income or loss.

Our provision for depreciation of utility property, plant, and equipment is recorded under the group method on a straight-line basis with rates computed in accordance with depreciation studies approved by regulatory authorities. The weighted-average depreciation rate for utility assets in service was approximately 2.8% for 2017, 2016, and 2015, reflecting the approximate weighted-average economic life of the property. This includes 2017 weighted-average depreciation rates for the following asset categories: 2.7% for transmission and distribution plant, 2.3% for gas storage facilities, 4.4% for general plant, and 2.7% for intangible and other fixed assets.

AFUDC. Certain additions to utility plant include AFUDC, which represents the net cost of debt and equity funds used during construction. AFUDC is calculated using actual interest rates for debt and authorized rates for ROE, if applicable. If short-term debt balances are less than the total balance of construction work in progress, then a composite AFUDC rate is used to represent interest on all debt funds, shown as a reduction to interest charges, and on ROE funds, shown as other income. While cash is not immediately recognized from recording AFUDC, it is realized in future years through rate recovery resulting from the higher utility cost of service. Our composite AFUDC rate was 5.5% in 2017, 0.7% in 2016, and 0.4% in 2015.

IMPAIRMENT OF LONG-LIVED ASSETS. We review the carrying value of long-lived assets whenever events or changes in circumstances indicate the carrying amount of the assets may not be recoverable. Factors that would necessitate an impairment assessment of long-lived assets include a significant adverse change in the extent or manner in which the asset is used, a significant adverse change in legal factors or business climate that could affect the value of the asset, or a significant decline in the observable market value or expected future cash flows of the asset, among others.

When such factors are present, we assess the recoverability by determining whether the carrying value of the asset will be recovered through expected future cash flows. An asset is determined to be impaired when the carrying value of the asset exceeds the expected undiscounted future cash flows from the use and eventual disposition of the asset. If an impairment is indicated, we record an impairment loss for the difference between the carrying value and the fair value of the long-lived assets. Fair value is estimated using appropriate valuation methodologies, which may include an estimate of discounted cash flows.

In the fourth quarter of 2017, we recognized a non-cash pre-tax impairment of long-lived assets at the Gill Ranch Facility of $192.5 million, which is included in our gas storage segment. We determined circumstances existed that indicated the carrying value of the assets may not be recoverable. Those circumstances included the completion of a comprehensive strategic review process that evaluated various alternatives including a potential sale, as well as contracting for available storage at lower than anticipated values for the coming storage year. Given these considerations, management was required to re-evaluate the estimated cash flows from our interests in the Gill Ranch Facility, and has determined that those estimated cash flows are no longer sufficient to cover the carrying value of the assets. We did not recognize any impairments in 2016 or 2015.

We used the income approach to estimate fair value, using the estimated future net cash flows of the Gill Ranch Facility. We also compared the results of the income approach to our own recent sale process experience and recent market comparable transactions in order to estimate fair value.

Cash and Cash Equivalents

For purposes of reporting cash flows, cash and cash equivalents include cash on hand plus highly liquid investment accounts with original maturity dates of three months or less. At December 31, 2017 and 2016, outstanding checks of approximately $4.8 million and $2.9 million, respectively, were included in accounts payable.

Revenue Recognition and Accrued Unbilled Revenue

Utility revenues, derived primarily from the sale and transportation of natural gas, are recognized upon delivery of the gas commodity or service to customers. Revenues include accruals for gas delivered but not yet billed to customers based on estimates of deliveries from meter reading dates to month end (accrued unbilled revenue). Accrued unbilled revenue is dependent upon a number of factors that require management's judgment, including total gas receipts and deliveries, customer use by billing cycle, and weather factors. Accrued unbilled revenue is reversed the following month when actual billings occur. Our accrued unbilled revenue at December 31, 2017 and 2016 was $62.4 million and $64.9 million, respectively.

Non-utility revenues are derived primarily from the gas storage segment. At our Mist underground storage facility, revenues are primarily firm service revenues in the form of fixed monthly reservation charges. At the Gill Ranch Facility, firm storage services resulting from short-term and long-term contracts are typically recognized in revenue ratably over the term of the contract regardless of the actual storage capacity utilized. In addition, we also have asset management service revenue from an independent energy marketing company that optimizes commodity, storage, and pipeline capacity release transactions. Under this agreement, guaranteed asset management revenue is recognized using a straight-line, pro-rata methodology over the term of each contract. Revenues earned above the guaranteed amount are recognized as they are earned.

Revenue Taxes
Revenue-based taxes are primarily franchise taxes, which are collected from customers and remitted to taxing authorities. Revenue taxes are included in operating revenues in the statement of comprehensive income or loss. Revenue taxes were $19.1 million, $17.1 million, and $18.0 million for 2017, 2016, and 2015, respectively.

Accounts Receivable and Allowance for Uncollectible Accounts
Accounts receivable consist primarily of amounts due for natural gas sales and transportation services to utility customers, plus amounts due for gas storage services. We establish an allowance for uncollectible accounts (allowance) for trade receivables, including accrued unbilled revenue, based on the aging of receivables, collection experience of past due account balances including payment plans, and historical trends of write-offs as a percent of revenues. A specific allowance is established and recorded for large individual customer receivables when amounts are identified as unlikely to be partially or fully recovered. Inactive accounts are written-off against the allowance after they are 120 days past due or when deemed uncollectible. Differences between our estimated allowance and actual write-offs will occur based on a number of factors, including changes in economic conditions, customer creditworthiness, and natural gas prices. The allowance for uncollectible accounts is adjusted quarterly, as necessary, based on information currently available.

Inventories
Utility gas inventories, which consist of natural gas in storage for the utility, are stated at the lower of average cost or net realizable value. The regulatory treatment of utility gas inventories provides for cost recovery in customer rates. Utility gas inventories injected into storage are priced in inventory based on actual purchase costs. Utility gas inventories withdrawn from storage are charged to cost of gas during the current period they are withdrawn at the weighted-average inventory cost.

Gas storage inventories, which primarily represent inventories at the Gill Ranch Facility, mainly consist of natural gas received as fuel-in-kind from storage customers. Gas storage inventories are valued at the lower of average cost or net realizable value. Cushion gas is not included in our inventory balances, is recorded at original cost, and is classified as a long-term plant asset.

Materials and supplies inventories consist of both utility and non-utility inventories and are stated at the lower of average cost or net realizable value.

Our utility and gas storage inventories totaled $36.7 million and $42.7 million at December 31, 2017 and 2016, respectively. At December 31, 2017 and 2016, our materials and supplies inventories totaled $11.3 million and $11.4 million, respectively.

Gas Reserves
Gas reserves are payments to acquire and produce natural gas reserves. Gas reserves are stated at cost, adjusted for regulatory amortization, with the associated deferred tax benefits recorded as liabilities on the balance sheet. The current portion is calculated based on expected gas deliveries within the next fiscal year. We recognize regulatory amortization of this asset on a volumetric basis calculated using the estimated gas reserves and the estimated therms extracted and sold each month. The amortization of gas reserves is recorded to cost of gas along with gas production revenues and production costs. See Note 11.

Derivatives
Derivatives are measured at fair value and recognized as either assets or liabilities on the balance sheet. Changes in the fair value of the derivatives are recognized currently in earnings unless specific regulatory or hedge accounting criteria are met. Accounting for derivatives and hedges provides an exception for contracts intended for normal purchases and normal sales for which physical delivery is probable. In addition, certain derivative contracts are approved by regulatory authorities for recovery or refund through customer rates. Accordingly, the changes in fair value of these approved contracts are deferred as regulatory assets or liabilities pursuant to regulatory accounting principles. Our financial derivatives generally qualify for deferral under regulatory accounting. Our index-priced physical derivative contracts also qualify for regulatory deferral accounting treatment.

Derivative contracts entered into for utility requirements after the annual PGA rate has been set and maturing during the PGA year are subject to the PGA incentive sharing mechanism. In Oregon we participate in a PGA sharing mechanism under which we are required to select either an 80% or 90% deferral of higher or lower gas costs such that the impact on current earnings from the gas cost sharing is either 20% or 10% of gas cost differences compared to PGA prices, respectively. For the PGA years in Oregon beginning November 1, 2017, 2016, and 2015, we selected the 90%, 90%, and 80% deferral of gas cost differences, respectively. In Washington, 100% of the differences between the PGA prices and actual gas costs are deferred. See Note 13.

Our financial derivatives policy sets forth the guidelines for using selected derivative products to support prudent risk management strategies within designated parameters. Our objective for using derivatives is to decrease the volatility of gas prices, earnings, and cash flows without speculative risk. The use of derivatives is permitted only after the risk exposures have been identified, are determined not to exceed acceptable tolerance levels, and are determined necessary to support normal business activities. We do not enter into derivative instruments for trading purposes.

Fair Value
In accordance with fair value accounting, we use the following fair value hierarchy for determining inputs for our debt, pension plan assets, and our derivative fair value measurements:
- Level 1: Valuation is based on quoted prices for identical instruments traded in active markets;

- Level 2: Valuation is based on quoted prices for similar instruments in active markets, quoted prices for identical or similar instruments in markets that are not active, and model-based valuation techniques for which all significant assumptions are observable in the market; and
- Level 3: Valuation is generated from model-based techniques that use significant assumptions not observable in the market. These unobservable assumptions reflect our own estimates of assumptions market participants would use in valuing the asset or liability.

When developing fair value measurements, it is our policy to use quoted market prices whenever available or to maximize the use of observable inputs and minimize the use of unobservable inputs when quoted market prices are not available. Fair values are primarily developed using industry-standard models that consider various inputs including: (a) quoted future prices for commodities; (b) forward currency prices; (c) time value; (d) volatility factors; (e) current market and contractual prices for underlying instruments; (f) market interest rates and yield curves; (g) credit spreads; and (h) other relevant economic measures. The Company considers liquid points for its natural gas hedging to be those points for which there are regularly published prices in a nationally recognized publication or where the instruments are traded on an exchange.

Income Taxes

We account for income taxes under the asset and liability method, which requires the recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been included in the financial statements. Under this method, deferred tax assets and liabilities are determined on the basis of the differences between the financial statement and tax basis of assets and liabilities using enacted tax rates in effect for the year in which the differences are expected to reverse. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the enactment date period unless a regulatory Order specifies deferral of the effect of the change in tax rates over a longer period of time.

Deferred income tax assets and liabilities are also recognized for temporary differences where the deferred income tax benefits or expenses have previously been flowed through in the ratemaking process of the regulated utility. Regulatory tax assets and liabilities are recorded on these deferred tax assets and liabilities to the extent we believe they will be recoverable from or refunded to customers in future rates.

Deferred investment tax credits on utility plant additions, which reduce income taxes payable, are deferred for financial statement purposes and amortized over the life of the related plant.

We recognize interest and penalties related to unrecognized tax benefits, if any, within income tax expense and accrued interest and penalties within the related tax liability line in the consolidated balance sheets. No accrued interest or penalties for uncertain tax benefits have been recorded. See Note 9.

Environmental Contingencies

Loss contingencies are recorded as liabilities when it is probable a liability has been incurred and the amount of the loss is reasonably estimable in accordance with accounting standards for contingencies. Estimating probable losses requires an analysis of uncertainties that often depend upon judgments about potential actions by third parties. Accruals for loss contingencies are recorded based on an analysis of potential results.

With respect to environmental liabilities and related costs, we develop estimates based on a review of information available from numerous sources, including completed studies and site specific negotiations. It is our policy to accrue the full amount of such liability when information is sufficient to reasonably estimate the amount of probable liability. When information is not available to reasonably estimate the probable liability, or when only the range of probable liabilities can be estimated and no amount within the range is more likely than another, it is our policy to accrue at the low end of the range. Accordingly, due to numerous uncertainties surrounding the course of environmental remediation and the preliminary nature of several site investigations, in some cases, we may not be able to reasonably estimate the high end of the range of possible loss. In those cases, we have disclosed the nature of the potential loss and the fact that the high end of the range cannot be reasonably estimated. See Note 15.

Subsequent Events

We monitor significant events occurring after the balance sheet date and prior to the issuance of the financial statements to determine the impacts, if any, of events on the financial statements to be issued. We do not have any subsequent events to report.

3. EARNINGS PER SHARE

Basic earnings or loss per share are computed using net income or loss and the weighted average number of common shares outstanding for each period presented. Diluted earnings per share are computed in the same manner, except it uses the weighted average number of common shares outstanding plus the effects of the assumed exercise of stock options and the payment of estimated stock awards from other stock-based compensation plans that are outstanding at the end of each period presented.

Antidilutive stock awards are excluded from the calculation of diluted earnings or loss per common share. Diluted earnings or loss per share are calculated as follows:

In thousands, except per share data	2017	2016	2015
Net income (loss)	$ (55,623)	$ 58,895	$ 53,703
Average common shares outstanding - basic	28,669	27,647	27,347
Additional shares for stock-based compensation plans (See Note 6)	—	132	70
Average common shares outstanding - diluted	28,669	27,779	27,417
Earnings (loss) per share of common stock - basic	$ (1.94)	$ 2.13	$ 1.96
Earnings (loss) per share of common stock - diluted	$ (1.94)	$ 2.12	$ 1.96
Additional information:			
Antidilutive shares	97	5	12

4. SEGMENT INFORMATION

We primarily operate in two reportable business segments: local gas distribution and gas storage. We also have other investments and business activities not specifically related to one of these two reporting segments, which are aggregated and reported as other. We refer to our local gas distribution business as the utility, and our gas storage segment and other as non-utility. Our utility segment also includes the utility portion of our Mist underground storage facility and our North Mist gas storage expansion in Oregon and NWN Gas Reserves, which is a wholly-owned subsidiary of Energy Corp. Our gas storage segment includes NWN Gas Storage, which is a wholly-owned subsidiary of NWN Energy, Gill Ranch, which is a wholly-owned subsidiary of NWN Gas Storage, the non-utility portion of Mist, and all third-party asset management services. Other includes NNG Financial, non-utility appliance retail center operations, NWN Water, which is pursuing investments in the water sector itself and through its wholly-owned subsidiary FWC Merger Sub, Inc., and NWN Energy's equity investment in TWH, which is pursuing development of a cross-Cascades transmission pipeline project. No individual customer accounts for over 10% of our operating revenues.

Local Gas Distribution

Our local gas distribution segment is a regulated utility principally engaged in the purchase, sale, and delivery of natural gas and related services to customers in Oregon and southwest Washington. As a regulated utility, we are responsible for building and maintaining a safe and reliable pipeline distribution system, purchasing sufficient gas supplies from producers and marketers, contracting for firm and interruptible transportation of gas over interstate pipelines to bring gas from the supply basins into our service territory, and re-selling the gas to customers subject to rates, terms, and conditions approved by the OPUC or WUTC. Gas distribution also includes taking customer-owned gas and transporting it from interstate pipeline connections, or city gates, to the customers' end-use facilities for a fee, which is approved by the OPUC or WUTC. Approximately 89% of our customers are located in Oregon and 11% in Washington. On an annual basis, residential and commercial customers typically account for around 60% of our utility's total volumes delivered and 90% of our utility's margin. Industrial customers largely account for the remaining volumes and utility margin. A small amount of utility margin is also derived from miscellaneous services, gains or losses from an incentive gas cost sharing mechanism, and other service fees.

Industrial sectors we serve include: pulp, paper, and other forest products; the manufacture of electronic, electrochemical and electrometallurgical products; the processing of farm and food products; the production of various mineral products; metal fabrication and casting; the production of machine tools, machinery, and textiles; the manufacture of asphalt, concrete, and rubber; printing and publishing; nurseries; government and educational institutions; and electric generation.

Gas Storage

Our gas storage segment includes natural gas storage services provided to customers primarily from two underground natural gas storage facilities: the Gill Ranch Facility and the non-utility portion of our Mist gas storage facility. In addition to earning revenue from customer storage contracts, we also use an independent energy marketing company to provide asset management services for utility and non-utility capacity, the results of which are included in this business segment.

Mist Gas Storage Facility

Earnings from non-utility assets at our Mist facility in Oregon are primarily related to firm storage capacity revenues. Earnings for the Mist facility also include revenue, net of amounts shared with utility customers, from management of utility assets at Mist and upstream pipeline capacity when not needed to serve utility customers. We retain 80% of the pre-tax income from these services when the costs of the capacity have not been included in utility rates, or 33% of the pre-tax income when the costs have been included in utility rates. The remaining 20% and 67%, respectively, are recorded to a deferred regulatory account for crediting back to utility customers.

Gill Ranch Gas Storage Facility
Gill Ranch has a joint project agreement with Pacific Gas and Electric Company (PG&E) to own and operate the Gill Ranch Facility, an underground natural gas storage facility near Fresno, California. Gill Ranch has a 75% undivided ownership interest in the facility and is also the operator of the facility, which offers storage services to the California market at market-based rates, subject to CPUC regulation including, but not limited to, service terms and conditions and tariff regulations. Although this is a jointly-owned property, each owner is independently responsible for financing its share of the Gill Ranch Facility. As such, the impairment of long-lived assets at the Gill Ranch Facility recognized in 2017 reflects our ownership interest. Revenues are primarily related to firm storage capacity as well as asset management revenues.

Other

We have non-utility investments and other business activities, which are aggregated and reported as other. Other primarily consists of an equity method investment in TWH, which was formed to build and operate an interstate gas transmission pipeline in Oregon (TWP), other pipeline assets in NNG Financial, and non-utility appliance retail center operations. For more information on TWP, see Note 12. Other also includes some corporate operating and non-operating revenues and expenses that cannot be allocated to utility operations. Upon closing agreements to purchase two water utilities, we expect them to be accounted for as other.

NNG Financial's assets primarily consist of an active, wholly-owned subsidiary which owns a 10% interest in an 18-mile interstate natural gas pipeline. NNG Financial's total assets were $0.4 million and $0.5 million at December 31, 2017 and 2016, respectively.

Segment Information Summary
Inter-segment transactions were immaterial for the periods presented. The following table presents summary financial information concerning the reportable segments:

In thousands	Utility	Gas Storage	Other	Total
2017				
Operating revenues	$ 732,942	$ 23,620	$ 5,611	$ 762,173
Depreciation and amortization	79,734	5,844	—	85,578
Income (loss) from operations (1)	132,807	(185,074)	(960)	(53,227)
Net income (loss) (2)	60,509	(116,209)	77	(55,623)
Capital expenditures	211,672	1,923	—	213,595
Total assets at December 31, 2017	2,961,326	59,583	18,837	3,039,746
2016				
Operating revenues	$ 650,477	$ 25,266	$ 224	$ 675,967
Depreciation and amortization	76,289	6,000	—	82,289
Income (loss) from operations	130,570	9,136	(426)	139,280
Net income (loss) (3)	54,567	4,303	25	58,895
Capital expenditures	138,074	1,437	—	139,511
Total assets at December 31, 2016	2,806,627	256,333	16,841	3,079,801
2015				
Operating revenues	$ 702,210	$ 21,356	$ 225	$ 723,791
Depreciation and amortization	74,410	6,513	—	80,923
Income (loss) from operations	119,215	5,032	1	124,248
Net income (loss) (3)	53,391	174	138	53,703
Capital expenditures	115,272	3,048	—	118,320
Total assets at December 31, 2015	2,791,623	261,750	16,037	3,069,410

(1) Includes $192.5 million for an impairment of long-lived assets at the Gill Ranch Facility in Gas Storage.
(2) Includes $21.9 million and $0.6 million of tax benefit in Gas Storage and Other, respectively, and $1.0 million of tax expense in Utility from the enactment of TCJA. Gas Storage also includes an after-tax impairment of long-lived assets at the Gill Ranch Facility of $141.5 million. The TCJA was enacted December 22, 2017 and resulted in the federal tax rate changing from 35% to 21%. The after-tax impairment charge is calculated using our new combined federal and state statutory rate of 26.5%.
(3) Includes $2.0 million in 2016 and $9.1 million in 2015 of after-tax regulatory environmental disallowance charges in Utility.

Utility Margin
Utility margin is a financial measure consisting of utility operating revenues, which are reduced by revenue taxes, the associated cost of gas, and environmental recovery revenues. The cost of gas purchased for utility customers is generally a pass-through cost in the amount of revenues billed to regulated utility customers. Environmental recovery revenues represent collections received from customers through our environmental recovery mechanism in Oregon. These collections are offset by the amortization of environmental liabilities, which is presented as environmental remediation expense in our operating expenses. By subtracting cost of gas and environmental remediation expense from utility operating revenues, utility margin provides a key metric used by our chief operating decision maker in assessing the performance of the utility segment. The gas storage segment and other emphasize growth in operating revenues as opposed to margin

because they do not incur a product cost (i.e. cost of gas sold) like the utility and, therefore, use operating revenues and net income to assess performance.

The following table presents additional segment information concerning utility margin:

In thousands		2017		2016		2015
Utility margin calculation:						
Utility operating revenues	$	732,942	$	650,477	$	702,210
Less: Utility cost of gas		325,019		260,588		327,305
Environmental remediation expense		15,291		13,298		3,513
Utility margin	$	392,632	$	376,591	$	371,392

5. COMMON STOCK

Common Stock

As of December 31, 2017 and 2016, we had 100 million shares of common stock authorized. As of December 31, 2017, we had reserved 43,058 shares for issuance of common stock under the Employee Stock Purchase Plan (ESPP) and 155,086 shares under our Dividend Reinvestment and Direct Stock Purchase Plan (DRPP). At our election, shares sold through our DRPP may be purchased in the open market or through original issuance of shares reserved for issuance under the DRPP.

The Restated Stock Option Plan (SOP) was terminated with respect to new grants in 2012; however, options granted before the Restated SOP was terminated will remain outstanding until the earlier of their expiration, forfeiture, or exercise. There were 91,688 options outstanding at December 31, 2017, which were granted prior to termination of the plan.

During November 2016, we completed an equity issuance consisting of an offering of 880,000 shares of its common stock along with a 30-day option for the underwriters to purchase an additional 132,000 shares. The offering closed on November 16, 2016 and resulted in a total issuance of 1,012,000 shares as both the initial offering and the underwriter option were fully executed. All shares were issued on November 16, 2016 at an offering price of $54.63 per share and resulted in total net proceeds of $52.8 million.

Stock Repurchase Program

We have a share repurchase program under which we may purchase our common shares on the open market or through privately negotiated transactions. We currently have Board authorization through May 2018 to repurchase up to an aggregate of the greater of 2.8 million shares or $100 million. No shares of common stock were repurchased pursuant to this program during the year ended December 31, 2017. Since the plan's inception in 2000, a total of 2.1 million shares have been repurchased at a total cost of $83.3 million.

Summary of Changes in Common Stock

The following table shows the changes in the number of shares of our common stock issued and outstanding:

In thousands	Shares
Balance, December 31, 2014	27,284
Sales to employees under ESPP	19
Stock-based compensation	78
Sales to shareholders under DRPP	46
Balance, December 31, 2015	27,427
Sales to employees under ESPP	18
Stock-based compensation	173
Equity Issuance	1,012
Balance, December 31, 2016	28,630
Sales to employees under ESPP	18
Stock-based compensation	88
Balance, December 31, 2017	28,736

6. STOCK-BASED COMPENSATION

Our stock-based compensation plans are designed to promote stock ownership in NW Natural by employees and officers. These compensation plans include a Long Term Incentive Plan (LTIP), an ESPP, and a Restated SOP.

Long Term Incentive Plan

The LTIP is intended to provide a flexible, competitive compensation program for eligible officers and key employees. Under the LTIP, shares of common stock are authorized for equity incentive grants in the form of stock, restricted stock, restricted stock units, stock options, or performance shares. An aggregate of 1,100,000 shares were authorized for issuance as of December 31, 2017. Shares awarded under the LTIP may be purchased on the open market or issued as original shares.

Of the 1,100,000 shares of common stock authorized for LTIP awards at December 31, 2017, there were 626,960 shares available for issuance under any type of award. This assumes market, performance, and service-based grants currently outstanding are awarded at the target level. There were no outstanding grants of restricted stock or stock options under the LTIP at December 31, 2017 or 2016. The LTIP stock awards are compensatory awards for which compensation expense is based on the fair value of stock awards, with expense being recognized over the performance and vesting period of the outstanding awards. Forfeitures are recognized as they occur.

Performance Shares

Since the LTIP's inception in 2001, performance shares, which incorporate market, performance, and service-based factors, have been granted annually with three-year performance periods. The following table summarizes performance share expense information:

Dollars in thousands	Shares[(1)]	Expense During Award Year[(2)]	Total Expense for Award
Estimated award:			
2015-2017 grant[(3)]	18,300	$ (346)	$ 1,169
Actual award:			
2014-2016 grant	31,388	168	1,685
2013-2015 grant	8,914	312	1,240

(1) In addition to common stock shares, a participant also receives a dividend equivalent cash payment equal to the number of shares of common stock received on the award payout multiplied by the aggregate cash dividends paid per share during the performance period.

(2) Amount represents the expense recognized in the third year of the vesting period noted above. For the 2015-2017 grant, we did not meet targets and reversed expense during 2017 that had been previously recognized.

(3) This represents the estimated number of shares to be awarded as of December 31, 2017 as certain performance share measures had been achieved. Amounts are subject to change with final payout amounts authorized by the Board of Directors in February 2018.

The aggregate number of performance shares granted and outstanding at the target and maximum levels were as follows:

Dollars in thousands	Performance Share Awards Outstanding		2017	Cumulative Expense
Performance Period	Target	Maximum	Expense/ (Reversal)	December 31, 2017
2015-17	29,967	59,934	$ (346)	$ 1,169
2016-18	24,826	49,652	337	815
2017-19	32,680	65,360	942	942
Total	87,473	174,946	$ 933	

For the 2015-2017 and 2016-2018 plan years, performance share awards are based on EPS and Return on Invested Capital (ROIC) factors and a total shareholder return (TSR factor) relative to the Dow Jones U.S. Gas Distribution peer group over the three-year performance period. Additionally, these plans are based on performance results achieved relative to specific core and non-core strategies (strategic factor). For the 2017-2019 plan year, performance share awards are based on the achievement of EPS and ROIC factors, which can be modified by a TSR factor relative to the performance of the Russell 2500 Utilities Index over the three-year performance period and a growth modifier based on accumulative EBITA measure.

Compensation expense is recognized in accordance with accounting standards for stock-based compensation and calculated based on performance levels achieved and an estimated fair value using the Monte-Carlo method. The weighted-average grant date fair value of nonvested shares at December 31, 2017 and 2016 was $56.40 and $50.83 per share, respectively. The weighted-average grant date fair value of shares granted during the year was $57.05 per share and for shares vested during the year was $52.02 per share. As of December 31, 2017, there was $2.8 million of unrecognized compensation expense related to the nonvested portion of performance awards expected to be recognized through 2019.

Restricted Stock Units

In 2012, we began granting RSUs under the LTIP instead of stock options under the Restated SOP. Generally, the RSUs awarded are forfeitable and include a performance-based threshold as well as a vesting period of four years from the grant date. Upon vesting, the RSU holder is issued one share of common stock plus a cash payment equal to the total amount of dividends paid per share between the grant date and vesting date of that portion of the RSU. The fair value of an RSU is equal to the closing market price of the Company's common stock on the grant date. During 2017, total RSU expense was $1.6 million compared to $1.5 million in 2016 and $1.3 million in 2015. As of December 31, 2017, there was $3.1 million of unrecognized compensation cost from grants of RSUs, which is expected to be recognized over a period extending through 2022.

Information regarding the RSU activity is summarized as follows:

	Number of RSUs	Weighted - Average Price Per RSU
Nonvested, December 31, 2014	70,794	$ 44.00
Granted	37,264	46.29
Vested	(19,003)	44.81
Forfeited	(468)	44.99
Nonvested, December 31, 2015	88,587	44.78
Granted	40,271	54.36
Vested	(29,488)	45.56
Forfeited	(9,397)	44.59
Nonvested, December 31, 2016	89,973	48.85
Granted	32,168	60.51
Vested	(35,341)	47.07
Forfeited	(2,278)	53.78
Nonvested, December 31, 2017	84,522	53.90

Restated Stock Option Plan

The Restated SOP was terminated for new option grants in 2012; however, options granted before the plan terminated will remain outstanding until the earlier of their expiration, forfeiture, or exercise. Any new grants of stock options would be made under the LTIP, however, no option grants have been awarded since 2012 and all stock options were vested as of December 31, 2015.

Options under the Restated SOP were granted to officers and key employees designated by a committee of our Board of Directors. All options were granted at an option price equal to the closing market price on the date of grant and may be exercised for a period of up to 10 years and seven days from the date of grant. Option holders may exchange shares they have owned for at least six months, valued at the current market price, to purchase shares at the option price.

Information regarding the Restated SOP activity is summarized as follows:

	Option Shares	Weighted - Average Price Per Share	Intrinsic Value *(In millions)*
Balance outstanding, December 31, 2014	416,088	$ 43.40	$ 2.7
Exercised	(62,900)	39.96	0.5
Forfeited	(500)	45.74	n/a
Balance outstanding, December 31, 2015	352,688	44.00	2.3
Exercised	(172,525)	43.61	2.0
Forfeited	—	n/a	n/a
Balance outstanding, December 31, 2016	180,163	44.38	2.8
Exercised	(88,275)	44.33	1.8
Forfeited	(200)	41.15	n/a
Balance outstanding and exercisable, December 31, 2017	91,688	44.43	1.4

During 2017, cash of $3.9 million was received for stock options exercised and $0.5 million related tax expense was recognized. The weighted-average remaining life of options exercisable and outstanding at December 31, 2017 was 2.47 years.

Employee Stock Purchase Plan

The ESPP allows employees to purchase common stock at 85% of the closing price on the trading day immediately preceding the initial offering date, which is set annually. Each eligible employee may purchase up to $21,199 worth of stock through payroll deductions over a period defined by the Board of Directors, which is currently a 12-month period, with shares issued at the end of the 12-month subscription period.

Stock-Based Compensation Expense

Stock-based compensation expense is recognized as operations and maintenance expense or is capitalized as part of construction overhead. The following table summarizes the financial statement impact of stock-based compensation under our LTIP, Restated SOP and ESPP:

In thousands	2017	2016	2015
Operations and maintenance expense, for stock-based compensation	$ 2,354	$ 2,370	$ 2,673
Income tax benefit	(930)	(924)	(1,012)
Net stock-based compensation effect on net income (loss)	$ 1,424	$ 1,446	$ 1,661
Amounts capitalized for stock-based compensation	$ 528	$ 554	$ 661

7. DEBT

Short-Term Debt

Our primary source of short-term funds is from the sale of commercial paper and bank loans. In addition to issuing commercial paper or bank loans to meet seasonal working capital requirements, short-term debt is used temporarily to fund capital requirements. Commercial paper and bank loans are periodically refinanced through the sale of long-term debt or equity securities. Our commercial paper program is supported by one or more committed credit facilities.

At December 31, 2017 and 2016, total short-term debt outstanding was $54.2 million and $53.3 million, respectively, which was comprised entirely of commercial paper. The weighted average interest rate at December 31, 2017 and 2016 was 1.9% and 0.8%, respectively.

The carrying cost of our commercial paper approximates fair value using Level 2 inputs, due to the short-term nature of the notes. See Note 2 for a description of the fair value hierarchy. At December 31, 2017, our commercial paper had a maximum remaining maturity of 11 days and an average remaining maturity of 6 days.

We have a $300.0 million credit agreement, with a feature that allows us to request increases in the total commitment amount up to a maximum amount of $450.0 million. The maturity of the agreement is December 20, 2019. We have a letter of credit of $100.0 million. Any principal and unpaid interest owed on borrowings under the agreement is due and payable on or before the expiration date. There were no outstanding balances under the agreement and no letters of credit issued or outstanding at December 31, 2017 and 2016.

The credit agreement requires that we maintain credit ratings with Standard & Poor's (S&P) and Moody's Investors Service, Inc. (Moody's) and notify the lenders of any change in our senior unsecured debt ratings or senior secured debt ratings, as applicable, by such rating agencies. A change in our debt ratings is not an event of default, nor is the maintenance of a specific minimum level of debt rating a condition of drawing upon the credit facility. However, interest rates on any loans outstanding under the credit facility are tied to debt ratings, which would increase or decrease the cost of any loans under the credit facility when ratings are changed.

The credit agreement also requires us to maintain a consolidated indebtedness to total capitalization ratio of 70% or less. Failure to comply with this covenant would entitle the lenders to terminate their lending commitments and accelerate the maturity of all amounts outstanding. We were in compliance with this covenant at December 31, 2017 and 2016.

Long-Term Debt

The issuance of FMBs, which includes our medium-term notes, under the Mortgage and Deed of Trust (Mortgage) is limited by eligible property, adjusted net earnings, and other provisions of the Mortgage. The Mortgage constitutes a first mortgage lien on substantially all of our utility property.

Maturities and Outstanding Long-Term Debt

Retirement of long-term debt for each of the 12-month periods through December 31, 2022 and thereafter are as follows:

In thousands	
Year	
2018	$ 97,000
2019	30,000
2020	75,000
2021	60,000
2022	—
Thereafter	524,700

The following table presents our debt outstanding as of December 31:

In thousands	2017	2016
First Mortgage Bonds		
7.000 % Series B due 2017	$ —	$ 40,000
1.545 % Series B due 2018	75,000	75,000
6.600 % Series B due 2018	22,000	22,000
8.310 % Series B due 2019	10,000	10,000
7.630 % Series B due 2019	20,000	20,000
5.370 % Series B due 2020	75,000	75,000
9.050 % Series A due 2021	10,000	10,000
3.176 % Series B due 2021	50,000	50,000
3.542 % Series B due 2023	50,000	50,000
5.620 % Series B due 2023	40,000	40,000
7.720 % Series B due 2025	20,000	20,000
6.520 % Series B due 2025	10,000	10,000
7.050 % Series B due 2026	20,000	20,000
3.211 % Series B due 2026	35,000	35,000
7.000 % Series B due 2027	20,000	20,000
2.822 % Series B due 2027	25,000	—
6.650 % Series B due 2027	19,700	19,700
6.650 % Series B due 2028	10,000	10,000
7.740 % Series B due 2030	20,000	20,000
7.850 % Series B due 2030	10,000	10,000
5.820 % Series B due 2032	30,000	30,000
5.660 % Series B due 2033	40,000	40,000
5.250 % Series B due 2035	10,000	10,000
4.000 % Series B due 2042	50,000	50,000
4.136 % Series B due 2046	40,000	40,000
3.685 % Series B due 2047	75,000	—
	786,700	726,700
Less: Current maturities	97,000	40,000
Total long-term debt	$ 689,700	$ 686,700

First Mortgage Bonds

We issued $100.0 million of FMBs in September 2017 consisting of $25.0 million with a coupon rate of 2.822% and maturity date in 2027 and $75 million with a coupon rate of 3.685% and maturity date in 2047.

Retirements of Long-Term Debt

We redeemed $40.0 million of FMBs with a coupon rate of 7.000% in August 2017.

Fair Value of Long-Term Debt

Our outstanding debt does not trade in active markets. We estimate the fair value of our debt using utility companies with similar credit ratings, terms, and remaining maturities to our debt that actively trade in public markets. These valuations are based on Level 2 inputs as defined in the fair value hierarchy. See Note 2.

The following table provides an estimate of the fair value of our long-term debt, including current maturities of long-term debt, using market prices in effect on the valuation date:

	December 31,	
In thousands	2017	2016
Gross long-term debt	$ 786,700	$ 726,700
Unamortized debt issuance costs	(6,813)	(7,377)
Carrying amount	$ 779,887	$ 719,323
Estimated fair value	$ 853,339	$ 793,339

8. PENSION AND OTHER POSTRETIREMENT BENEFIT COSTS

We maintain a qualified non-contributory defined benefit pension plan, non-qualified supplemental pension plans for eligible executive officers and other key employees, and other postretirement employee benefit plans. We also have a qualified defined contribution plan (Retirement K Savings Plan) for all eligible employees. The qualified defined benefit pension plan and Retirement K Savings Plan have plan assets, which are held in qualified trusts to fund retirement benefits.

Effective January 1, 2007 and 2010, the qualified defined benefit pension plans and postretirement benefits for non-union employees and union employees, respectively, were closed to new participants.

These plans were not available to employees of our non-utility subsidiaries. Non-union and union employees hired or re-hired after December 31, 2006 and 2009, respectively, and employees of NW Natural subsidiaries are provided an enhanced Retirement K Savings Plan benefit.

Effective December 31, 2012, the qualified defined benefit pension plans for non-union and union employees were merged into a single plan.

The following table provides a reconciliation of the changes in benefit obligations and fair value of plan assets, as applicable, for the pension and other postretirement benefit plans, excluding the Retirement K Savings Plan, and a summary of the funded status and amounts recognized in the consolidated balance sheets as of December 31:

	Postretirement Benefit Plans			
	Pension Benefits		Other Benefits	
In thousands	2017	2016	2017	2016
Reconciliation of change in benefit obligation:				
Obligation at January 1	$ 457,839	$ 445,628	$ 29,395	$ 31,049
Service cost	7,090	7,083	341	391
Interest cost	18,111	18,399	1,141	1,175
Net actuarial (gain) loss	34,829	7,688	(213)	(1,488)
Benefits paid[1]	(31,580)	(20,959)	(1,737)	(1,732)
Obligation at December 31	$ 486,289	$ 457,839	$ 28,927	$ 29,395
Reconciliation of change in plan assets:				
Fair value of plan assets at January 1	$ 257,714	$ 249,338	$ —	$ —
Actual return on plan assets	40,308	12,593	—	—
Employer contributions	21,483	16,742	1,737	1,732
Benefits paid[1]	(31,580)	(20,959)	(1,737)	(1,732)
Fair value of plan assets at December 31	$ 287,925	$ 257,714	$ —	$ —
Funded status at December 31	$ (198,364)	$ (200,125)	$ (28,927)	$ (29,395)

(1) In 2017, we completed a partial buy-out of our qualified defined benefit pension plan in which $9.3 million of plan assets and $8.7 million liabilities were transferred to an insurer to provide annuities for buy-out plan participants.

Our qualified defined benefit pension plan has an aggregate benefit obligation of $449.7 million and $423.5 million at December 31, 2017 and 2016, respectively, and fair values of plan assets of $287.9 million and $257.7 million, respectively. The following table presents amounts realized through regulatory assets or in other comprehensive loss (income) for the years ended December 31:

	Regulatory Assets						Other Comprehensive Loss (Income)		
	Pension Benefits			Other Postretirement Benefits			Pension Benefits		
In thousands	2017	2016	2015	2017	2016	2015	2017	2016	2015
Net actuarial loss (gain)	$ 12,177	$ 14,005	$ 419	$ (214)	$ (1,488)	$ 2,724	$ 2,777	$ (1,196)	$ (2,549)
Settlement Loss	—	—	—	—	—	—	—	193	—
Amortization of:									
Prior service cost	(127)	(230)	(230)	468	468	(197)	—	—	—
Actuarial loss	(14,802)	(13,238)	(16,372)	(696)	(705)	(554)	(946)	1,386	(2,236)
Total	$ (2,752)	$ 537	$ (16,183)	$ (442)	$ (1,725)	$ 1,973	$ 1,831	$ 383	$ (4,785)

The following table presents amounts recognized in regulatory assets and accumulated other comprehensive loss (AOCL) at December 31:

	Regulatory Assets				AOCL	
	Pension Benefits		Other Postretirement Benefits		Pension Benefits	
In thousands	2017	2016	2017	2016	2017	2016
Prior service cost (credit)	$ 49	$ 176	$ (2,206)	$ (2,675)	$ —	$ 1
Net actuarial loss	175,035	177,660	6,964	7,874	13,266	11,434
Total	$ 175,084	$ 177,836	$ 4,758	$ 5,199	$ 13,266	$ 11,435

The following table presents amounts recognized in AOCL and the changes in AOCL related to our non-qualified employee benefit plans:

	Year Ended December 31,	
In thousands	2017	2016
Beginning balance	$ (6,951)	$ (7,162)
Amounts reclassified to AOCL	(2,794)	(1,196)
Amounts reclassified from AOCL:		
Amortization of actuarial losses	946	1,386
Loss from plan settlement	—	193
Total reclassifications before tax	(1,848)	383
Tax expense (benefit)	361	(172)
Total reclassifications for the period	(1,487)	211
Ending balance	$ (8,438)	$ (6,951)

In 2018, an estimated $17.3 million will be amortized from regulatory assets to net periodic benefit costs, consisting of $17.7 million of actuarial losses, and $0.4 million of prior service credits. A total of $0.8 million will be amortized from AOCL to earnings related to actuarial losses in 2018.

Our assumed discount rate for the pension plan and other postretirement benefit plans was determined independently based on the Citigroup Above Median Curve (discount rate curve), which uses high quality corporate bonds rated AA- or higher by S&P or Aa3 or higher by Moody's. The discount rate curve was applied to match the estimated cash flows in each of our plans to reflect the timing and amount of expected future benefit payments for these plans.

Our assumed expected long-term rate of return on plan assets for the qualified pension plan was developed using a weighted-average of the expected returns for the target asset portfolio. In developing the expected long-term rate of return assumption, consideration was given to the historical performance of each asset class in which the plan's assets are invested and the target asset allocation for plan assets.

Our investment strategy and policies for qualified pension plan assets held in the retirement trust fund were approved by our Retirement Committee, which is composed of senior management with the assistance of an outside investment consultant. The policies set forth the guidelines and objectives governing the investment of plan assets. Plan assets are invested for total return with appropriate consideration for liquidity, portfolio risk, and return expectations. All investments are expected to satisfy the prudent investments rule under the Employee Retirement Income Security Act of 1974. The approved asset classes may include cash and short-term investments, fixed income, common stock and convertible securities, absolute and real return strategies, real estate, and investments in NW Natural securities. Plan assets may be invested in separately managed accounts or in commingled or mutual funds. Investment re-balancing takes place periodically as needed, or when significant cash flows occur, in order to maintain the allocation of assets within the stated target ranges. The retirement trust fund is not currently invested in NW Natural securities.

The following table presents the pension plan asset target allocation at December 31, 2017:

Asset Category	Target Allocation
U.S. large cap equity	29.3%
U.S. small/mid cap equity	6.9
Non-U.S. equity	28.0
Emerging markets equity	11.8
Long government/credit	17.5
High yield bonds	2.0
Emerging market debt	3.5
Real estate funds	1.0

Our non-qualified supplemental defined benefit plan obligations were $36.6 million and $34.3 million at December 31, 2017 and 2016, respectively. These plans are not subject to regulatory deferral, and the changes in actuarial gains and losses, prior service costs, and transition assets or obligations are recognized in AOCL, net of tax until they are amortized as a component of net periodic benefit cost. These are unfunded, non-qualified plans with no plan assets; however, we indirectly fund a significant portion of our obligations with company and trust-owned life insurance and other assets.

Our other postretirement benefit plans are unfunded plans but are subject to regulatory deferral. The actuarial gains and losses, prior service costs, and transition assets or obligations for these plans are recognized as a regulatory asset.

Net periodic benefit costs consist of service costs, interest costs, the amortization of actuarial gains and losses, and the expected returns on plan assets, which are based in part on a market-related valuation of assets. The market-related valuation reflects differences between expected returns and actual investment returns with the differences recognized over a three-year or less period from the year in which they occur, thereby reducing year-to-year net periodic benefit cost volatility.

The following table provides the components of net periodic benefit cost for our pension and other postretirement benefit plans for the years ended December 31:

	Pension Benefits			Other Postretirement Benefits		
In thousands	2017	2016	2015	2017	2016	2015
Service cost	$ 7,090	$ 7,083	$ 8,267	$ 341	$ 391	$ 527
Interest cost	18,111	18,399	18,360	1,141	1,175	1,179
Expected return on plan assets	(20,433)	(20,054)	(20,676)	—	—	—
Amortization of prior service costs	127	231	231	(468)	(468)	197
Amortization of net actuarial loss	15,748	14,624	18,609	696	705	554
Settlement expense	—	193	—	—	—	—
Net periodic benefit cost	20,643	20,476	24,791	1,710	1,803	2,457
Amount allocated to construction	(6,597)	(5,746)	(6,834)	(587)	(600)	(808)
Amount deferred to regulatory balancing account[1]	(6,542)	(6,252)	(8,241)	—	—	—
Net amount charged to expense	$ 7,504	$ 8,478	$ 9,716	$ 1,123	$ 1,203	$ 1,649

(1) The deferral of defined benefit pension plan expenses above or below the amount set in rates was approved by the OPUC, with recovery of these deferred amounts through the implementation of a balancing account. The balancing account includes the expectation of higher net periodic benefit costs than costs recovered in rates in the near-term with lower net periodic benefit costs than costs recovered in rates expected in future years. Deferred pension expense balances include accrued interest at the utility's authorized rate of return, with the equity portion of the interest recognized when amounts are collected in rates.

Net periodic benefit costs are reduced by amounts capitalized to utility plant based on approximately 25% to 35% payroll overhead charge. In addition, a certain amount of net periodic benefit costs are recorded to the regulatory balancing account for pensions.

Net periodic pension cost less amounts charged to capital accounts and regulatory balancing accounts are expenses recognized in earnings.

The following table provides the assumptions used in measuring periodic benefit costs and benefit obligations for the years ended December 31:

	Pension Benefits			Other Postretirement Benefits		
	2017	2016	2015	2017	2016	2015
Assumptions for net periodic benefit cost:						
Weighted-average discount rate	3.99%	4.17%	3.82%	3.85%	4.00%	3.74%
Rate of increase in compensation	3.25-4.5%	3.25-4.5%	3.25-5.0%	n/a	n/a	n/a
Expected long-term rate of return	7.50%	7.50%	7.50%	n/a	n/a	n/a
Assumptions for year-end funded status:						
Weighted-average discount rate	3.52%	4.00%	4.21%	3.44%	3.85%	4.00%
Rate of increase in compensation	3.25-4.5%	3.25-4.5%	3.25-4.5%	n/a	n/a	n/a
Expected long-term rate of return	7.50%	7.50%	7.50%	n/a	n/a	n/a

The assumed annual increase in health care cost trend rates used in measuring other postretirement benefits as of December 31, 2017 was 7.50%. These trend rates apply to both medical and prescription drugs. Medical costs and prescription drugs are assumed to decrease gradually each year to a rate of 4.75% by 2026.

Assumed health care cost trend rates can have a significant effect on the amounts reported for the health care plans; however, other postretirement benefit plans have a cap on the amount of costs reimbursable by us.

A one percentage point change in assumed health care cost trend rates would have the following effects:

In thousands	1% Increase	1% Decrease
Effect on net periodic postretirement health care benefit cost	$ 44	$ (39)
Effect on the accumulated postretirement benefit obligation	478	(428)

We review mortality assumptions annually and will update for material changes as necessary. In 2017, our mortality rate assumptions were updated from RP-2006 mortality tables for employees and healthy annuitants with a fully generational projection using scale MP-2016 to corresponding RP-2006 mortality tables using scale MP-2017, which partially offset increases of our projected benefit obligation.

The following table provides information regarding employer contributions and benefit payments for the qualified pension plan, non-qualified pension plans, and other postretirement benefit plans for the years ended December 31, and estimated future contributions and payments:

In thousands	Pension Benefits	Other Benefits
Employer Contributions:		
2016	$ 16,742	$ 1,732
2017	21,483	1,737
2018 (estimated)	17,710	1,835
Benefit Payments:		
2015	35,923	2,018
2016	20,959	1,732
2017	31,580	1,737
Estimated Future Benefit Payments:		
2018	22,679	1,835
2019	23,546	1,871
2020	24,542	1,861
2021	25,471	1,904
2022	26,095	1,886
2023-2027	145,065	9,261

Employer Contributions to Company-Sponsored Defined Benefit Pension Plans

We make contributions to our qualified defined benefit pension plans based on actuarial assumptions and estimates, tax regulations, and funding requirements under federal law. The Pension Protection Act of 2006 (the Act) established funding requirements for defined benefit plans. The Act establishes a 100% funding target over seven years for plan years beginning after December 31, 2008. In 2012 the Moving Ahead for Progress in the 21st Century Act (MAP-21) legislation changed several provisions affecting pension plans, including temporary funding relief and Pension Benefit Guaranty Corporation (PBGC) premium increases, which reduces the level of minimum required contributions in the near-term but generally increases contributions in the long-run and increases the operational costs of running a pension plan. In 2014, the Highway and Transportation Funding Act (HATFA) was signed and extends certain aspects of MAP-21 as well as modifies the phase-out periods for the limitations.

Our qualified defined benefit pension plan is currently underfunded by $161.7 million at December 31, 2017. Including the impacts of MAP-21 and HATFA, we made cash contributions totaling $19.4 million to our qualified defined benefit pension plan for 2017. During 2018, we expect to make contributions of approximately $15.5 million to this plan.

Multiemployer Pension Plan

In addition to the Company-sponsored defined benefit plans presented above, prior to 2014 we contributed to a multiemployer pension plan for our utility's union employees known as the Western States Office and Professional Employees International Union Pension Fund (Western States Plan). The plan's employer identification number is 94-6076144. Effective December 22, 2013, we withdrew from the plan, which was a noncash transaction. Vested participants will receive all benefits accrued through the date of withdrawal. As the plan was underfunded at the time of withdrawal, we were assessed a withdrawal liability of $8.3 million, plus interest, which requires NW Natural to pay $0.6 million each year to the plan for 20 years beginning in July 2014. The cost of the withdrawal liability was deferred to a regulatory account on the balance sheet.

We made payments of $0.6 million for 2017, and as of December 31, 2017 the liability balance was $7.1 million. For 2016 and 2015, contributions to the plan were $0.6 million and $0.6 million, respectively, which was approximately 4% to 5% of the total contributions to the plan by all employer participants in those years.

Defined Contribution Plan

The Retirement K Savings Plan is a qualified defined contribution plan under Internal Revenue Code Sections 401(a) and 401(k). Employer contributions totaled $5.4 million, $4.6 million, and $3.7 million for 2017, 2016, and 2015, respectively. The Retirement K Savings Plan includes an Employee Stock Ownership Plan.

Deferred Compensation Plans

The supplemental deferred compensation plans for eligible officers and senior managers are non-qualified plans. These plans are designed to enhance the retirement savings of employees and to assist them in strengthening their financial security by providing an incentive to save and invest regularly.

Fair Value

Below is a description of the valuation methodologies used for assets measured at fair value. In cases where the pension plan is invested through a collective trust fund or mutual fund, the fund's market value is utilized. Market values for investments directly owned are also utilized.

U.S. LARGE CAP EQUITY and U.S. SMALL/MID CAP EQUITY. These are Level 1 and non-published net asset value (NAV) assets. The Level 1 assets consist of directly held stocks and mutual funds with a readily determinable fair value, including a published NAV. The non-published NAV assets consist of commingled trusts where NAV is not published but the investment can be readily disposed of at NAV or market value. Directly held stocks are valued at the closing price reported in the active market on which the individual security is traded. Mutual funds and commingled trusts are valued at NAV and the unit price, respectively. This asset class includes investments primarily in U.S. common stocks.

NON-U.S. EQUITY. These are Level 1 and non-published NAV assets. The Level 1 assets consist of directly held stocks, and the non-published NAV assets consist of commingled trusts where the NAV/unit price is not published but the investment can be readily disposed of at the NAV/unit price. Directly held stocks are valued at the closing price reported in the active market on which the individual security is traded, and the commingled trusts are valued at unit price. This asset class includes investments primarily in foreign equity common stocks.

EMERGING MARKETS EQUITY. These are non-published NAV assets consisting of an open-end mutual fund where the NAV price is not published but the investment can be readily disposed of at the NAV, and a commingled trust where the investment can be readily disposed of at unit price. This asset class includes investments primarily in common stocks in emerging markets.

FIXED INCOME. These are non-published NAV assets consisting of a commingled trust, valued at unit price, where unit price is not published, but the investment can be readily disposed of at the unit price. This asset class includes investments primarily in investment grade debt and fixed income securities.

LONG GOVERNMENT/CREDIT. These are non-published NAV and Level 2 assets. The non-published NAV assets include commingled trusts, valued at unit price, where unit price is not published, but the investment can be readily disposed of at the unit price. The Level 2 assets consist of directly held fixed-income securities, with readily determinable fair values, whose values are determined by closing prices if available and by matrix prices for illiquid securities. This asset class includes long duration fixed income investments primarily in U.S. treasuries, U.S. government agencies, municipal securities, mortgage-backed securities, asset-backed securities, as well as U.S. and international investment-grade corporate bonds.

HIGH YIELD BONDS. These are non-published NAV assets, consisting of a limited partnership and a commingled trust where the valuation is not published but the investment can be readily disposed of at market value, valued at NAV or unit price, respectively. This asset class includes investments primarily in high yield bonds.

EMERGING MARKET DEBT. This is a non-published NAV asset consisting of a commingled trust with a readily determinable fair value, where unit price is not published, but the investment can be readily disposed of at the unit price. This asset class includes investments primarily in emerging market debt.

REAL ESTATE. These are Level 1 and non-published NAV assets. The Level 1 asset is a mutual fund with a readily determinable fair value, including a published NAV. The non-published NAV asset is a commingled trust with a readily determinable fair value, where unit price is not published, but the investment can be readily disposed of at the unit price. This asset class includes investments primarily in real estate investment trust (REIT) equity securities globally.

ABSOLUTE RETURN STRATEGY. This is a non-published NAV asset consisting of a hedge fund of funds where the valuation is not published. This hedge fund of funds is winding down. Based on recent dispositions, we believe the remaining investment is fairly valued. The hedge fund of funds is valued at the weighted average value of investments in various hedge funds, which in turn are valued at the closing price of the underlying securities. This asset class primarily includes investments in common stocks and fixed income securities.

CASH AND CASH EQUIVALENTS. These are Level 1 and non-published NAV assets. The Level 1 assets consist of cash in U.S. dollars, which can be readily disposed of at face value. The non-published NAV assets represent mutual funds without published NAV's but the investment can be readily disposed of at the NAV. The mutual funds are valued at the NAV of the shares held by the plan at the valuation date.

The preceding valuation methods may produce a fair value calculation that is not indicative of net realizable value or reflective of future fair values. Although we believe these valuation methods are appropriate and consistent with other market participants, the use of different methodologies or assumptions to determine the fair value of certain investments could result in a different fair value measurement at the reporting date.

Investment securities are exposed to various financial risks including interest rate, market, and credit risks. Due to the level of risk associated with certain investment securities, it is reasonably possible that changes in the values of our investment securities will occur in the near term and such changes could materially affect our investment account balances and the amounts reported as plan assets available for benefit payments.

The following table presents the fair value of plan assets, including outstanding receivables and liabilities, of the retirement trust fund:

In thousands	December 31, 2017				
Investments	Level 1	Level 2	Level 3	Non-Published NAV[1]	Total
U.S. large cap equity	$ —	$ —	$ —	$ 102,851	$ 102,851
U.S. small/mid cap equity	—	—	—	16,423	16,423
Non-U.S. equity	21,211	—	—	56,075	77,286
Emerging markets equity	—	—	—	28,743	28,743
Fixed income	—	—	—	2,781	2,781
Long government/credit	—	—	—	33,081	33,081
High yield bonds	—	—	—	2,777	2,777
Emerging market debt	—	—	—	12,605	12,605
Real estate	—	—	—	5,544	5,544
Absolute return strategy	—	—	—	189	189
Cash and cash equivalents	82	—	—	5,533	5,615
Total investments	$ 21,293	$ —	$ —	$ 266,602	$ 287,895

	December 31, 2016				
Investments	Level 1	Level 2	Level 3	Non-Published NAV[1]	Total
U.S. large cap equity	$ 49,841	$ —	$ —	$ 5,655	$ 55,496
U.S. small/mid cap equity	18,629	—	—	10,232	28,861
Non-U.S. equity	22,404	—	—	25,346	47,750
Emerging markets equity	—	—	—	13,457	13,457
Fixed income	—	—	—	6,719	6,719
Long government/credit	—	34,955	—	17,960	52,915
High yield bonds	—	—	—	14,072	14,072
Emerging market debt	—	—	—	8,504	8,504
Real estate	17,857	—	—	882	18,739
Absolute return strategy	—	—	—	3,111	3,111
Cash and cash equivalents	$ 9	$ —	$ —	$ 2,482	$ 2,491
Total investments	$ 108,740	$ 34,955	$ —	$ 108,420	$ 252,115

	December 31,	
	2017	2016
Receivables:		
Accrued interest and dividend income	$ 30	$ 451
Due from broker for securities sold	—	5,170
Total receivables	$ 30	$ 5,621
Liabilities:		
Due to broker for securities purchased	$ —	$ 22
Total investment in retirement trust	$ 287,925	$ 257,714

(1) The fair value for these investments is determined using Net Asset Value per share (NAV) as of December 31, as a practical expedient, and therefore they are not classified within the fair value hierarchy. These investments primarily consist of institutional investment products, for which the NAV is generally not publicly available.

9. INCOME TAX

The following table provides a reconciliation between income taxes calculated at the statutory federal tax rate and the provision for income taxes reflected in the consolidated statements of comprehensive income or loss for December 31:

Dollars in thousands	2017	2016	2015
Income taxes (benefits) at federal statutory rate	$(30,233)	$ 34,863	$ 31,310
Increase (decrease):			
State income tax, net of federal	(5,784)	4,582	4,195
Amortization of investment tax credits	(4)	(41)	(118)
Differences required to be flowed-through by regulatory commissions	2,357	2,357	2,357
Gains on company and trust-owned life insurance	(872)	(594)	(766)
Effect of TCJA	(21,429)	—	—
Deferred Tax Rate Differential Post-TCJA	26,947	—	—
Other, net	(1,739)	(453)	(1,225)
Total provision for income taxes (benefits)	$(30,757)	$ 40,714	$ 35,753
Effective tax rate	35.6%	40.9%	40.0%

The effective income tax rate for 2017 compared to 2016 changed primarily as a result of the TCJA, the equity portion of AFUDC and excess tax benefits related to stock-based compensation. The effective income tax rate increase from 2016 compared to 2015 was primarily the result of lower depletion deductions from gas reserves activity in 2016.

The provision for current and deferred income taxes consists of the following at December 31:

In thousands	2017	2016	2015
Current			
Federal	$ 16,403	$ 7,402	$ 10,558
State	4,892	2,042	61
	21,295	9,444	10,619
Deferred			
Federal	(41,134)	26,219	18,729
State	(10,918)	5,051	6,405
	(52,052)	31,270	25,134
Total provision for income taxes (loss benefits)	$ (30,757)	$ 40,714	$ 35,753

At December 31, 2017 and 2016, regulatory income tax assets of $21.3 million and $43.0 million, respectively, were recorded, a portion of which is recorded in current assets. These regulatory income tax assets primarily represent future rate recovery of deferred tax liabilities, resulting from differences in utility plant financial statement and tax bases and utility plant removal costs, which were previously flowed through for rate making purposes and to take into account the additional future taxes, which will be generated by that recovery. These deferred tax liabilities, and the associated regulatory income tax assets, are currently being recovered through customer rates. At December 31, 2017, we had a regulatory income tax asset of $0.9 million representing probable future rate recovery of deferred tax liabilities resulting from the equity portion of AFUDC.

The following table summarizes the total provision (benefit) for income taxes for the utility and non-utility business segments for December 31:

In thousands	2017	2016	2015
Utility:			
Current	$ 21,453	$ 10,300	$ 15,890
Deferred	19,479	28,749	20,834
Deferred investment tax credits	(4)	(41)	(118)
	40,928	39,008	36,606
Non-utility business segments:			
Current	(158)	(856)	(5,271)
Deferred	(71,527)	2,562	4,418
	(71,685)	1,706	(853)
Total provision for income taxes	$(30,757)	$ 40,714	$ 35,753

The following table summarizes the tax effect of significant items comprising our deferred income tax accounts at December 31:

In thousands	2017	2016
Deferred tax liabilities:		
Plant and property	$ 296,114	$ 428,642
Regulatory income tax assets	22,209	43,048
Regulatory liabilities	29,114	48,291
Non-regulated deferred tax liabilities	933	51,446
Total	$ 348,370	$ 571,427
Deferred tax assets:		
Regulatory income tax liabilities	$ 56,470	$ —
Non-regulated deferred tax assets	17,796	—
Pension and postretirement obligations	3,512	4,493
Alternative minimum tax credit carryforward	66	9,853
Total	$ 77,844	$ 14,346
Deferred income tax liabilities, net	$ 270,526	$ 557,081
Deferred investment tax credits	—	4
Deferred income taxes and investment tax credits	$ 270,526	$ 557,085

Management assesses the available positive and negative evidence to estimate if sufficient taxable income will be generated to utilize the existing deferred tax assets. Based upon this assessment, we have determined we are more likely than not to realize all deferred tax assets recorded as of December 31, 2017.

As a result of certain realization requirements prescribed in the accounting guidance for income taxes, the tax benefit of statutory depletion is recognized no earlier than the year in which the depletion is deductible on our federal income tax return. Income tax expense decreased by $0.9 million in 2015 as a result of realizing deferred depletion benefit from 2013 and 2014. This benefit is included in Other, net in the statutory rate reconciliation table.

Uncertain tax positions are accounted for in accordance with accounting standards that require management's assessment of the anticipated settlement outcome of material uncertain tax positions taken in a prior year, or planned to be taken in the current year. Until such positions are sustained, we would not recognize the uncertain tax benefits resulting from such positions. No reserves for uncertain tax positions were recorded as of December 31, 2017, 2016, or 2015.

Our federal income tax returns for tax years 2013 and earlier are closed by statute. The IRS Compliance Assurance Process (CAP) examination of the 2013, 2014, and 2015 tax years have been completed. There were no material changes to these returns as filed. The 2016 and 2017 tax years are currently under IRS CAP examination. Our 2018 CAP application has been accepted by the IRS. Under the CAP program, we work with the IRS to identify and resolve material tax matters before the tax return is filed each year. As of December 31, 2017, income tax years 2014 through 2016 remain open for state examination.

U.S. Federal TCJA Matters

On December 22, 2017, the TCJA was enacted and permanently lowers the U.S. federal corporate income tax rate to 21% from the existing maximum rate of 35%, effective for our tax year beginning January 1, 2018. The TCJA includes specific provisions related to regulated public utilities that provide for the continued deductibility of interest expense and the elimination of bonus depreciation for property acquired after September 27, 2017.

As a result of the reduction of the U.S. corporate income tax rate to 21%, U.S. GAAP requires deferred tax assets and liabilities be revalued as of the date of enactment, with resulting tax effects accounted for in the reporting period of enactment. We recorded a net revaluation of deferred tax asset and liability balances of $196.4 million as of December 31, 2017. This revaluation had no impact on our 2017 cash flows.

The net change in our utility deferred taxes, that were determined to have previously been included in ratemaking activities by the OPUC and WUTC, was recorded as a net regulatory liability that is expected to accrue to the future benefit of customers. It is possible that this estimated regulatory liability balance of $213.3 million, which includes a gross up for income taxes of $56.5 million, may increase or decrease as a result of future regulatory guidance by the OPUC and WUTC or as additional authoritative interpretation of the TCJA becomes available.

The change in our utility deferred taxes of $18.2 million, associated with tax benefits that have previously been flowed through to customers or for the equity portion of AFUDC, resulted in an identical reduction in the associated regulatory assets. This change had no impact on our income tax expense. The net change in our utility deferred taxes, that were determined to have been previously excluded from ratemaking activities by the OPUC and WUTC, and the change in deferred taxes associated with the gas storage segment and other non-regulated operations, was recorded as a net reduction of income tax expense of $21.4 million.

Under pre-TCJA law, business interest is generally deductible in the determination of taxable income. The TCJA imposes a new limitation on the deductibility of net business interest expense in excess of approximately 30% of adjusted taxable income. Taxpayers operating in the trade or business of public regulated utilities are excluded from these new interest expense limitations.

There is uncertainty whether the new interest expense limitation may apply to our non-regulated operations. The legislative history indicates that all members of a consolidated or affiliated group are treated as a single taxpayer with respect to applying business interest limitations. Future authoritative guidance may indicate that net interest expense must be allocated between regulated and non-regulated activities within the consolidated group. Until such time that additional guidance is available that eliminates this uncertainty, we are unable to estimate whether the new interest limitation rules will impact our future operating results. The new interest limitation rules are effective for taxable years beginning after December 31, 2017. There is no grandfathering for debt instruments outstanding prior to such date. Net business interest expense amounts disallowed may be carried forward indefinitely and treated as interest in succeeding taxable years.

The TCJA generally provides for immediate full expensing for qualified property acquired and placed in service after September 27, 2017 and before January 1, 2023. This would generally provide for accelerated cost recovery for capital investments. However, the definition of qualified property excludes property used in the trade or business of a public regulated utility. The definition of utility trade or business is the same as that used by the TCJA with respect to the imposition of the net interest expense limitation discussed above. As a result, a similar uncertainty exists with respect to whether the exclusion from full expensing will apply to our full consolidated group, which primarily operates as a regulated public utility, or whether full expensing will be available to our non-regulated activities.

An additional uncertainty exists with respect to whether 50% bonus depreciation, which was in effect prior to the TCJA, will apply to property for which a contract was entered into or significant construction had occurred prior to September 27, 2017, but that was not placed in service until after that date. We excluded all assets placed in service by the consolidated group after September 27, 2017 from bonus depreciation. If future authoritative guidance indicates that bonus depreciation is available to us for these capital expenditures, this would primarily result in a decrease to our current income taxes payable and an increase in regulatory liability.

The SEC staff issued Staff Accounting Bulletin 118, which provides guidance on accounting for the tax effects of the TCJA. SAB 118 provides a measurement period that should not extend beyond one year from the TCJA enactment date for companies to complete the accounting under ASC 740. To the extent that a company's accounting for certain income tax effects of the TCJA is incomplete but it is able to determine a reasonable estimate, it must record a provisional estimate in the financial statements. Consistent with SAB 118, the determination to exclude all assets placed in service after September 27, 2017 from bonus depreciation is provisional.

We primarily operate in the States of Oregon and Washington. The extent to which a particular state adopts the U.S. Internal Revenue Code directly affects the application of the enacted federal changes of the TCJA to its taxable income computation. To varying degrees, Oregon and Washington corporate business tax approaches rely on federal income tax law, including the Internal Revenue Code and the associated Treasury regulations. It is possible that the federal changes resulting from the TCJA will cause states to reassess their future conformity, however, we have evaluated the state impacts of the TCJA under current law.

Oregon automatically adopts changes to the U.S. Internal Revenue Code related to the calculation of consolidated corporate taxable income. By both State statute and administrative rule, Oregon corporation excise tax law, as related to the definition of taxable income, is tied to federal tax law as applicable to our tax year. Changes enacted to the definition of federal taxable income by the TCJA are effective for Oregon tax purposes in the same manner as for federal tax purposes. As a result, the net interest limitation and full expensing exclusions, discussed above, apply to Oregon as well.

Washington State does not have a corporate income tax, but rather imposes a tax on our gross receipts. The TCJA does not include a change to the definition of gross receipts, or the timing of their recognition, that is currently anticipated to impact us. As a result, no change to Washington State reporting is anticipated.

10. PROPERTY, PLANT, AND EQUIPMENT

The following table sets forth the major classifications of our property, plant, and equipment and accumulated depreciation at December 31:

In thousands	2017	2016
Utility plant in service	$2,975,217	$2,843,243
Utility construction work in progress	159,924	62,264
Less: Accumulated depreciation	942,879	903,096
Utility plant, net	2,192,262	2,002,411
Non-utility plant in service	75,639	299,378
Non-utility construction work in progress	4,671	3,931
Less: Accumulated depreciation	17,598	44,820
Non-utility plant, net	62,712	258,489
Total property, plant, and equipment	$2,254,974	$2,260,900
Capital expenditures in accrued liabilities	$ 34,976	$ 9,547

The weighted average depreciation rate for utility assets was 2.8% for utility assets during 2017, 2016, and 2015. The weighted average depreciation rate for non-utility assets was 1.9% in 2017, 2.0% in 2016, and 2.2% in 2015.

Accumulated depreciation does not include the accumulated provision for asset removal costs of $360.9 million and $341.1 million at December 31, 2017 and 2016, respectively. These accrued asset removal costs are reflected on the balance sheet as regulatory liabilities. See Note 2. During 2017 and 2016, we did not acquire any equipment under capital leases.

11. GAS RESERVES

We have invested $188 million through our gas reserves program in the Jonah Field located in Wyoming as of December 31, 2017. Gas reserves are stated at cost, net of regulatory amortization, with the associated deferred tax benefits recorded as liabilities on the consolidated balance sheets. Our investment in gas reserves provides long-term price protection for utility customers through the original agreement with Encana Oil & Gas (USA) Inc. under which we invested $178 million and the amended agreement with Jonah Energy LLC under which an additional $10 million was invested.

We entered into our original agreements with Encana in 2011 under which we hold working interests in certain sections of the Jonah Field. Gas produced in these sections is sold at prevailing market prices, and revenues from such sales, net of associated operating and production costs and amortization, are credited to the utility's cost of gas. The cost of gas, including a carrying cost for the rate base investment, is included in our annual Oregon PGA filing, which allows us to recover these costs through customer rates. Our investment under the original agreement, less accumulated amortization and deferred taxes, earns a rate of return.

In March 2014, we amended the original gas reserves agreement in order to facilitate Encana's proposed sale of its interest in the Jonah field to Jonah Energy. Under the amendment, we ended the drilling program with Encana, but increased our working interests in our assigned sections of the Jonah field. We also retained the right to invest in new wells with Jonah Energy. Under the amended agreement we still have the option to invest in additional wells on a well-by-well basis with drilling costs and resulting gas volumes shared at our amended proportionate working interest for each well in which we invest. We elected to participate in some of the additional wells drilled in 2014, but have not had the opportunity to participate in additional wells since 2014. However, we may have the opportunity to participate in more wells in the future.

Gas produced from the additional wells is included in our Oregon PGA at a fixed rate of $0.4725 per therm, which approximates the 10-year hedge rate plus financing costs at the inception of the investment.

Gas reserves acted to hedge the cost of gas for approximately 6%, 8% and 11% of our utility's gas supplies for the years ended December 31, 2017, 2016, and 2015 respectively.

The following table outlines our net gas reserves investment at December 31:

In thousands	2017	2016
Gas reserves, current	$ 15,704	$ 15,926
Gas reserves, non-current	171,832	171,610
Less: Accumulated amortization	87,779	71,426
Total gas reserves(1)	99,757	116,110
Less: Deferred taxes on gas reserves	22,712	28,119
Net investment in gas reserves	$ 77,045	$ 87,991

(1) Our net investment in additional wells included in total gas reserves was $5.8 million and $6.7 million at December 31, 2017 and 2016, respectively.

Our investment is included in our consolidated balance sheets under gas reserves with our maximum loss exposure limited to our investment balance.

12. INVESTMENTS

Investments include financial investments in life insurance policies, and equity method investments in certain partnerships and limited liability companies. The following table summarizes our other investments at December 31:

In thousands	2017	2016
Investments in life insurance policies	$ 50,792	$ 52,719
Investments in gas pipeline	13,669	13,767
Other	1,902	1,890
Total other investments	$ 66,363	$ 68,376

Investment in Life Insurance Policies

We have invested in key person life insurance contracts to provide an indirect funding vehicle for certain long-term employee and director benefit plan liabilities. The amount in the above table is reported at cash surrender value, net of policy loans.

Investments in Gas Pipeline

TWP, a wholly-owned subsidiary of TWH, is pursuing the development of a new gas transmission pipeline that would provide an interconnection with our utility distribution system. NWN Energy, a wholly-owned subsidiary of NW Natural, owns 50% of TWH, and 50% is owned by TransCanada American Investments Ltd., an indirect wholly-owned subsidiary of TransCanada Corporation.

Variable Interest Entity (VIE) Analysis

TWH is a VIE, with our investment in TWP reported under equity method accounting. We have determined we are not the primary beneficiary of TWH's activities as we only have a 50% share of the entity, and there are no stipulations that allow us a disproportionate influence over it. Our investments in TWH and TWP are included in other investments on our balance sheet. If we do not develop this investment, then our maximum loss exposure related to TWH is limited to our equity investment balance, less our share of any cash or other assets available to us as a 50% owner. Our investment balance in TWH was $13.4 million at December 31, 2017 and 2016.

Impairment Analysis

Our investments in nonconsolidated entities accounted for under the equity method are reviewed for impairment at each reporting period and following updates to our corporate planning assumptions. If it is determined a loss in value is other than temporary, a charge is recognized for the difference between the investment's carrying value and its estimated fair value. Fair value is based on quoted market prices when available or on the present value of expected future cash flows. Differing assumptions could affect the timing and amount of a charge recorded in any period.

In 2011, TWP withdrew its original application with the FERC for a proposed natural gas pipeline in Oregon and informed FERC that it intended to re-file an application to reflect changes in the project scope aligning the project with the region's current and future gas infrastructure needs. TWP continues working with customers in the Pacific Northwest to further understand their gas transportation needs and determine the commercial support for a revised pipeline proposal. A new FERC certificate application is expected to be filed to reflect a revised scope based on these regional needs.

Our equity investment was not impaired at December 31, 2017 as the fair value of expected cash flows from planned development exceeded our remaining equity investment of $13.4 million at December 31, 2017. However, if we learn that the project is not viable or will not go forward, we could be required to recognize a maximum charge of up to approximately $13.4 million based on the current amount of our equity investment, net of cash and working capital at TWP. We will continue to monitor and update our impairment analysis as required.

13. DERIVATIVE INSTRUMENTS

We enter into financial derivative contracts to hedge a portion of our utility's natural gas sales requirements. These contracts include swaps, options, and combinations of option contracts. We primarily use these derivative financial instruments to manage commodity price variability. A small portion of our derivative hedging strategy involves foreign currency exchange contracts.

We enter into these financial derivatives, up to prescribed limits, primarily to hedge price variability related to our physical gas supply contracts as well as to hedge spot purchases of natural gas. The foreign currency forward contracts are used to hedge the fluctuation in foreign currency exchange rates for pipeline demand charges paid in Canadian dollars.

In the normal course of business, we also enter into indexed-price physical forward natural gas commodity purchase contracts and options to meet the requirements of utility customers. These contracts qualify for regulatory deferral accounting treatment.

We also enter into exchange contracts related to the third-party asset management of our gas portfolio, some of which are derivatives that do not qualify for hedge accounting or regulatory deferral, but are subject to our regulatory sharing agreement. These derivatives are recognized in operating revenues in our gas storage segment, net of amounts shared with utility customers.

Notional Amounts

The following table presents the absolute notional amounts related to open positions on our derivative instruments:

	At December 31,	
In thousands	2017	2016
Natural gas (in therms):		
Financial	429,100	477,430
Physical	520,268	535,450
Foreign exchange	$ 7,669	$ 7,497

Purchased Gas Adjustment (PGA)

Derivatives entered into by the utility for the procurement or hedging of natural gas for future gas years generally receive regulatory deferral accounting treatment. In general, our commodity hedging for the current gas year is completed prior to the start of the gas year, and hedge prices are reflected in our weighted-average cost of gas in the PGA filing. Hedge contracts entered into after the start of the PGA period are subject to our PGA incentive sharing mechanism in Oregon. We entered the 2017-18 and 2016-17 gas year with our forecasted sales volumes hedged at 49% and 48% in financial swap and option contracts, and 26% and 27% in physical gas supplies, respectively. Hedge contracts entered into prior to our PGA filing, in September 2017, were included in the PGA for the 2017-18 gas year. Hedge contracts entered into after our PGA filing, and related to subsequent gas years, may be included in future PGA filings and qualify for regulatory deferral.

Unrealized and Realized Gain/Loss

The following table reflects the income statement presentation for the unrealized gains and losses from our derivative instruments:

	December 31, 2017		December 31, 2016	
In thousands	Natural gas commodity	Foreign exchange	Natural gas commodity	Foreign exchange
Benefit (expense) to cost of gas	$ (26,000)	$ 107	$ 22,746	$ (130)
Operating revenues	(1,021)	—	995	—
Amounts deferred to regulatory accounts on balance sheet	26,665	(107)	(23,394)	130
Total gain (loss) in pre-tax earnings	$ (356)	$ —	$ 347	$ —

UNREALIZED GAIN/LOSS. Outstanding derivative instruments related to regulated utility operations are deferred in accordance with regulatory accounting standards. The cost of foreign currency forward and natural gas derivative contracts are recognized immediately in the cost of gas; however, costs above or below the amount embedded in the current year PGA are subject to a regulatory deferral tariff and therefore, are recorded as a regulatory asset or liability.

REALIZED GAIN/LOSS. We realized net losses of $7.8 million and $26.9 million for the years ended December 31, 2017 and 2016, respectively, from the settlement of natural gas financial derivative contracts. Realized gains and losses are recorded in cost of gas, deferred through our regulatory accounts, and amortized through customer rates in the following year.

Credit Risk Management of Financial Derivatives Instruments

No collateral was posted with or by our counterparties as of December 31, 2017 or 2016. We attempt to minimize the potential exposure to collateral calls by counterparties to manage our liquidity risk. Counterparties generally allow a certain credit limit threshold before requiring us to post collateral against loss positions. Given our counterparty credit limits and portfolio diversification, we were not subject to collateral calls in 2017 or 2016. Our collateral call exposure is set forth under credit support agreements, which generally contain credit limits. We could also be subject to collateral call exposure where we have agreed to provide adequate assurance, which is not specific as to the amount of credit limit allowed, but could potentially require additional collateral in the event of a material adverse change.

Based on current commodity financial swap and option contracts outstanding, which reflect unrealized losses of $22.3 million at December 31, 2017, we have estimated the level of collateral demands, with and without potential adequate assurance calls, using current gas prices and various credit downgrade rating scenarios for NW Natural as follows:

		Credit Rating Downgrade Scenarios			
In thousands	(Current Ratings) A+/A3	BBB+/ Baa1	BBB/ Baa2	BBB-/ Baa3	Specul-ative
With Adequate Assurance Calls	$ —	$ —	$ —	$ (5,428)	$(15,422)
Without Adequate Assurance Calls	—	—	—	(5,428)	(11,594)

Our financial derivative instruments are subject to master netting arrangements; however, they are presented on a gross basis in our consolidated balance sheets. We and our counterparties have the ability to set-off obligations to each other under specified circumstances. Such circumstances may include a defaulting party, a credit change due to a merger affecting either party, or any other termination event.

If netted by counterparty, our derivative position would result in an asset of $2.9 million and a liability of $23.3 million as of December 31, 2017. As of December 31, 2016, our derivative position would have resulted in an asset of $18.8 million and a liability of $0.7 million.

We are exposed to derivative credit and liquidity risk primarily through securing fixed price natural gas commodity swaps to hedge the risk of price increases for our natural gas purchases made on behalf of customers. We utilize master netting arrangements through International Swaps and Derivatives Association contracts to minimize this risk along with collateral support agreements with counterparties based on their credit ratings. In certain cases, we require guarantees or letters of credit from counterparties to meet our minimum credit requirement standards.

Our financial derivatives policy requires counterparties to have a certain investment-grade credit rating at the time the derivative instrument is entered into, and the policy specifies limits on the contract amount and duration based on each counterparty's credit rating. We do not speculate with derivatives; instead, we use derivatives to hedge our exposure above risk tolerance limits. Any increase in market risk created by the use of derivatives should be offset by the exposures they modify.

We actively monitor our derivative credit exposure and place counterparties on hold for trading purposes or require other forms of credit assurance, such as letters of credit, cash collateral, or guarantees as circumstances warrant. Our ongoing assessment of counterparty credit risk includes consideration of credit ratings, credit default swap spreads, bond market credit spreads, financial condition, government actions, and market news. We use a Monte-Carlo simulation model to estimate the change in credit and liquidity risk from the volatility of natural gas prices. The results of the model are used to establish earnings-at-risk trading limits. Our credit risk for all outstanding financial derivatives at December 31, 2017 extends to March 2020.

We could become materially exposed to credit risk with one or more of our counterparties if natural gas prices experience a significant increase. If a counterparty were to become insolvent or fail to perform on its obligations, we could suffer a material loss; however, we would expect such a loss to be eligible for regulatory deferral and rate recovery, subject to a prudence review. All of our existing counterparties currently have investment-grade credit ratings.

Fair Value

In accordance with fair value accounting, we include non-performance risk in calculating fair value adjustments. This includes a credit risk adjustment based on the credit spreads of our counterparties when we are in an unrealized gain position, or on our own credit spread when we are in an unrealized loss position. The inputs in our valuation models include natural gas futures, volatility, credit default swap spreads, and interest rates. Additionally, our assessment of non-performance risk is generally derived from the credit default swap market and from bond market credit spreads. The impact of the credit risk adjustments for all outstanding derivatives was immaterial to the fair value calculation at December 31, 2017. As of December 31, 2017 and 2016, the net fair value was a liability of $20.3 million and an asset of $18.1 million, respectively, using significant other observable, or Level 2, inputs. No Level 3 inputs were used in our derivative valuations, and there were no transfers between Level 1 or Level 2 during the years ended December 31, 2017 and 2016.

14. COMMITMENTS AND CONTINGENCIES

Leases

We lease land, buildings, and equipment under agreements that expire in various years, including a 99-year land lease that extends through 2108. Rental costs were $7.5 million, $6.2 million, and $5.5 million for the years ended December 31, 2017, 2016, and 2015, respectively, a portion of which is capitalized. The following table reflects the future minimum lease payments due under non-cancelable leases at December 31, 2017. These commitments relate principally to the lease of our office headquarters, underground gas storage facilities, and computer equipment.

In thousands	Operating leases	Capital leases	Minimum lease payments
2018	$ 5,378	$ 3	$ 5,381
2019	5,379	—	5,379
2020	6,945	—	6,945
2021	7,482	—	7,482
2022	7,629	—	7,629
Thereafter	169,411	—	169,411
Total	$ 202,224	$ 3	$ 202,227

In October 2017, we entered into a 20-year operating lease agreement for a new headquarters in Portland, Oregon in anticipation of the expiration of our current lease in 2020. Payments under the new lease are expected to commence in 2020. Total estimated base rent payments over the life of the lease are approximately $160 million and have been included in the table above. We have the option to extend the term of the lease for two additional seven-year periods.

Additionally, the lease was analyzed in consideration of build-to-suit lease accounting guidance, and we concluded that we are the accounting owner of the asset during construction. As a result, we recognized $0.5 million in Property, plant and equipment and an obligation in Other non-current liabilities for the same amount on our consolidated balance sheet at December 31, 2017.

Gas Purchase and Pipeline Capacity Purchase and Release Commitments

We have signed agreements providing for the reservation of firm pipeline capacity under which we are required to make fixed monthly payments for contracted capacity. The pricing component of the monthly payment is established, subject to change, by U.S. or Canadian regulatory bodies. In addition, we have entered into long-term sale agreements to release firm pipeline capacity. We also enter into short-term and long-term gas purchase agreements.

The aggregate amounts of these agreements were as follows at December 31, 2017:

In thousands	Gas Purchase Agreements	Pipeline Capacity Purchase Agreements	Pipeline Capacity Release Agreements
2018	$ 63,944	$ 79,891	$ 3,581
2019	2,729	82,129	—
2020	2,729	77,028	—
2021	2,273	65,630	—
2022	—	60,050	—
Thereafter	—	601,844	—
Total	71,675	966,572	3,581
Less: Amount representing interest	601	174,542	24
Total at present value	$ 71,074	$ 792,030	$ 3,557

Our total payments for fixed charges under capacity purchase agreements were $85.3 million for 2017, $85.0 million for 2016, and $85.2 million for 2015. Included in the amounts were reductions for capacity release sales of $4.5 million for 2017, $4.5 million for 2016, and $4.4 million for 2015. In addition, per-unit charges are required to be paid based on the actual quantities shipped under the agreements. In certain take-or-pay purchase commitments, annual deficiencies may be offset by prepayments subject to recovery over a longer term if future purchases exceed the minimum annual requirements.

Environmental Matters

Refer to Note 15 for a discussion of environmental commitments and contingencies.

15. ENVIRONMENTAL MATTERS

We own, or previously owned, properties that may require environmental remediation or action. We estimate the range of loss for environmental liabilities based on current remediation technology, enacted laws and regulations, industry experience gained at similar sites, and an assessment of the probable level of involvement and financial condition of other potentially responsible parties (PRPs). When amounts are prudently expended related to site remediation of those sites described herein, we have a recovery mechanism in place to collect 96.68% of remediation costs from Oregon customers, and we are allowed to defer environmental remediation costs allocated to customers in Washington annually until they are reviewed for prudence at a subsequent proceeding.

Our sites are subject to the remediation process prescribed by the Environmental Protection Agency (EPA) and the Oregon Department of Environmental Quality (ODEQ). The process begins with a remedial investigation (RI) to determine the nature and extent of contamination and then a risk assessment (RA) to establish whether the contamination at the site poses unacceptable risks to humans and the environment. Next, a feasibility study (FS) or an engineering evaluation/cost analysis (EE/CA) evaluates various remedial alternatives. It is at this point in the process when we are able to estimate a range of remediation costs and record a reasonable potential remediation liability, or make an adjustment to our existing liability. From this study, the regulatory agency selects a remedy and issues a Record of Decision (ROD).

After a ROD is issued, we would seek to negotiate a consent decree or consent judgment for designing and implementing the remedy. We would have the ability to further refine estimates of remediation liabilities at that time.

Remediation may include treatment of contaminated media such as sediment, soil and groundwater, removal and disposal of media, institutional controls such as legal restrictions on future property use, or natural recovery. Following construction of the remedy, the EPA and ODEQ also have requirements for ongoing maintenance, monitoring, and other post-remediation care that may continue for many years. Where appropriate and reasonably known, we will provide for these costs in our remediation liabilities described below.

Due to the numerous uncertainties surrounding the course of environmental remediation and the preliminary nature of several site investigations, in some cases, we may not be able to reasonably estimate the high end of the range of possible loss. In those cases, we have disclosed the nature of the possible loss and the fact that the high end of the range cannot be reasonably estimated where a range of potential loss is available. Unless there is an estimate within the range of possible losses that is more likely than other cost estimates within that range, we record the liability at the low end of this range. It is likely changes in these estimates and ranges will occur throughout the remediation process for each of these sites due to our continued evaluation and clarification concerning our responsibility, the complexity of environmental laws and regulations, and the determination by regulators of remediation alternatives. In addition to remediation costs, we could also be subject to Natural Resource Damages (NRD) claims from third-party tribal entities. We will assess the likelihood and probability of each claim and recognize a liability if deemed appropriate. Refer to "Other Portland Harbor" below.

Environmental Sites

The following table summarizes information regarding liabilities related to environmental sites, which are recorded in other current liabilities and other noncurrent liabilities on the balance sheet at December 31:

	Current Liabilities		Non-Current Liabilities	
In thousands	2017	2016	2017	2016
Portland Harbor site:				
Gasco/Siltronic Sediments	$ 2,683	$ 869	$ 45,346	$ 43,972
Other Portland Harbor	1,949	1,970	4,163	4,148
Gasco/Siltronic Upland site	13,422	10,657	47,835	49,183
Central Service Center site	25	73	—	—
Front Street site	1,009	906	10,757	7,786
Oregon Steel Mills	—	—	179	179
Total	$ 19,088	$ 14,475	$ 108,280	$ 105,268

PORTLAND HARBOR SITE. The Portland Harbor is an EPA listed Superfund site that is approximately 10 miles long on the Willamette River and is adjacent to NW Natural's Gasco uplands sites. We are one of over one hundred PRPs to the Superfund site. In January 2017, the EPA issued its Record of Decision, which selects the remedy fund for the clean-up of the Portland Harbor site (Portland Harbor ROD). The Portland Harbor ROD estimates the present value total cost at approximately $1.05 billion with an accuracy between -30% and +50% of actual costs.

Our potential liability is a portion of the costs of the remedy for the entire Portland Harbor Superfund site. The cost of that remedy is expected to be allocated among more than 100 PRPs. In addition, we are actively pursuing clarification and flexibility under the ROD in order to better understand our obligation under the clean-up. We are also participating in a non-binding allocation process with the other PRPs in an effort to resolve our potential liability. The Portland Harbor ROD does not provide any additional clarification around allocation of costs among PRPs and, as a result of issuance of the Portland Harbor ROD, we have not modified any of our recorded liabilities at this time.

We manage our liability related to the Superfund site as two distinct remediation projects: the Gasco/Siltronic Sediments and Other Portland Harbor projects.

Gasco/Siltronic Sediments. In 2009, NW Natural and Siltronic Corporation entered into a separate Administrative Order on Consent with the EPA to evaluate and design specific remedies for sediments adjacent to the Gasco uplands and Siltronic uplands sites. We submitted a draft EE/CA to the EPA in May 2012 to provide the estimated cost of potential remedial alternatives for this site. At this time, the estimated costs for the various sediment remedy alternatives in the draft EE/CA, for the additional studies and design work needed before the cleanup can occur, and for regulatory oversight throughout the clean-up range from $48.0 million to $350 million. We have recorded a liability of $48.0 million for the sediment clean-up, which reflects the low end of the range. At this time, we believe sediments at this site represent the largest portion of our liability related to the Portland Harbor site discussed above.

Other Portland Harbor. While we still believe liabilities associated with the Gasco/Siltronic sediments site represent our largest exposure, we do have other potential exposures associated with the Portland Harbor ROD, including NRD costs and harborwide clean-up costs (including downstream petroleum contamination), for which allocations among the PRPs have not yet been determined.

The Company and other parties have signed a cooperative agreement with the Portland Harbor Natural Resource Trustee council to participate in a phased NRD assessment to estimate liabilities to support an early restoration-based settlement of NRD claims. One member of this Trustee council, the Yakama Nation, withdrew from the council in 2009, and in 2017, filed suit against the Company and 29 other parties seeking remedial costs and NRD assessment costs associated with the Portland Harbor, set forth in the complaint. The complaint seeks recovery of alleged costs totaling $0.3 million in connection with the selection of a remedial action for the Portland Harbor as well as declaratory judgment for unspecified future remedial action costs and for costs to assess the injury, loss, or destruction of natural resources resulting from the release of hazardous substances at and from the Portland Harbor site. The Yakama Nation has filed two amended complaints addressing certain pleading defects and dismissing the State of Oregon. We have recorded a liability for NRD claims which is at the low end of the range of the potential liability; the high end of the range cannot be reasonably estimated at this time. The NRD liability is not included in the aforementioned range of costs provided in the Portland Harbor ROD.

GASCO UPLANDS SITE. A predecessor of NW Natural, Portland Gas and Coke Company, owned a former gas manufacturing plant that was closed in 1958 (Gasco site) and is adjacent to the Portland Harbor site described above. The Gasco site has been under investigation by us for environmental contamination under the ODEQ Voluntary Clean-Up Program (VCP). It is not included in the range of remedial costs for the Portland Harbor site noted above. We manage the Gasco site in two parts: the uplands portion and the groundwater source control action.

We submitted a revised Remedial Investigation Report for the uplands to ODEQ in May 2007. In March 2015, ODEQ approved the RA, enabling us to begin work on the FS in 2016. We have recognized a liability for the remediation of the uplands portion of the site which is at the low end of the range of potential liability; the high end of the range cannot be reasonably estimated at this time.

In October 2016, ODEQ and NW Natural agreed to amend their VCP agreement to incorporate a portion of the Siltronic property adjacent to the Gasco site formerly owned by Portland Gas & Coke between 1939 and 1960 into the Gasco RA and FS, excluding the uplands for Siltronic. Previously, we were conducting an investigation of manufactured gas plant constituents on the entire Siltronic uplands for ODEQ. Siltronic will be working with ODEQ directly on environmental impacts to the remainder of its property.

In September 2013, we completed construction of a groundwater source control system, including a water treatment station, at the Gasco site. We have estimated the cost associated with the ongoing operation of the system and have recognized a liability which is at the low end of the range of potential cost. We cannot estimate the high end of the range at this time due to the uncertainty associated with the duration of running the water treatment station, which is highly dependent on the remedy determined for both the upland portion as well as the final remedy for our Gasco sediment exposure.

OTHER SITES. In addition to those sites above, we have environmental exposures at three other sites: Central Service Center, Front Street, and Oregon Steel Mills. We may have exposure at other sites that have not been identified at this time. Due to the uncertainty of the design of remediation, regulation, timing of the remediation, and in the case of the Oregon Steel Mills site, pending litigation, liabilities for each of these sites have been recognized at their respective low end of the range of potential liability; the high end of the range could not be reasonably estimated at this time.

Central Service Center site. We are currently performing an environmental investigation of the property under ODEQ's Independent Cleanup Pathway. This site is on ODEQ's list of sites with confirmed releases of hazardous substances, and cleanup is necessary.

Front Street site. The Front Street site was the former location of a gas manufacturing plant we operated (the former Portland Gas Manufacturing site, or PGM). At ODEQ’s request, we conducted a sediment and source control investigation and provided findings to ODEQ. In December 2015, we completed a FS on the former Portland Gas Manufacturing site.

In July 2017, ODEQ issued the PGM ROD. The ROD specifies the selected remedy, which requires a combination of dredging, capping, treatment, and natural recovery. In addition, the selected remedy also requires institutional controls and long-term inspection and maintenance. We revised the liability in the second quarter of 2017 to incorporate the estimated undiscounted cost of approximately $10.5 million for the selected remedy. Further, we have recognized an additional liability of $1.3 million for additional studies and design costs as well as regulatory oversight throughout the clean-up. We plan to complete the remedial design in 2018 and expect to construct the remedy details during 2019.

Oregon Steel Mills site. Refer to the “Legal Proceedings,” below.

Site Remediation and Recovery Mechanism (SRRM)

We have an SRRM through which we track and have the ability to recover past deferred and future prudently incurred environmental remediation costs allocable to Oregon, subject to an earnings test, for those sites identified therein. In the February 2015 Order establishing the SRRM (2015 Order), the OPUC addressed outstanding issues related to the SRRM, which required us to forego the collection of $15 million out of approximately $95 million in total environmental remediation expenses and associated carrying costs.

As a follow-up to the 2015 Order, the OPUC issued an additional Order in January 2016 (2016 Order) regarding the SRRM implementation in which the OPUC: (1) disallowed the recovery of $2.8 million of interest earned on the previously disallowed environmental expenditure amounts; (2) clarified the state allocation of 96.68% of environmental remediation costs for all environmental sites to Oregon; and (3) confirmed our treatment of $13.8 million of expenses put into the SRRM amortization account was correct and in compliance with prior OPUC orders. As a result of the 2016 Order, we recognized a $3.3 million non-cash charge in the first quarter, of which $2.8 million is reflected in other income and expense, net and $0.5 million is included in operations and maintenance expense.

COLLECTIONS FROM OREGON CUSTOMERS. Under the SRRM collection process there are three types of deferred environmental remediation expense:

- Pre-review - This class of costs represents remediation spend that has not yet been deemed prudent by the OPUC. Carrying costs on these remediation expenses are recorded at our authorized cost of capital. The Company anticipates the prudence review for annual costs and approval of the earnings test prescribed by the OPUC to occur by the third quarter of the following year.
- Post-review - This class of costs represents remediation spend that has been deemed prudent and allowed after applying the earnings test, but is not yet included in amortization. We earn a carrying cost on these amounts at a rate equal to the five-year treasury rate plus 100 basis points.
- Amortization - This class of costs represents amounts included in current customer rates for collection and is generally calculated as one-fifth of the post-review deferred balance. We earn a carrying cost equal to the amortization rate determined annually by the OPUC, which approximates a short-term borrowing rate.

In addition to the collection amount noted above, the Order also provides for the annual collection of $5.0 million from Oregon customers through a tariff rider. As we collect amounts from customers, we recognize these collections as revenue and separately amortize an equal and offsetting amount of our deferred regulatory asset balance through the environmental remediation operating expense line shown separately in the operating expense section of the income statement.

We received total environmental insurance proceeds of approximately $150.0 million as a result of settlements from our litigation that was dismissed in July 2014. Under the 2015 OPUC Order, one-third of the Oregon allocated proceeds were applied to costs deferred through 2012 with the remaining two-thirds applied to costs at a rate of $5.0 million per year plus interest over the following 20 years. We accrue interest on the insurance proceeds in the customer's favor at a rate equal to the five-year treasury rate plus 100 basis points. As of December 31, 2017, we have applied $68.2 million of insurance proceeds to prudently incurred remediation costs allocated to Oregon.

The following table presents information regarding the total regulatory asset deferred as of December 31:

In thousands	2017	2016
Deferred costs and interest [1]	$ 45,546	$ 53,039
Accrued site liabilities [2]	126,950	119,443
Insurance proceeds and interest	(94,170)	(98,523)
Total regulatory asset deferral[1]	$ 78,326	$ 73,959
Current regulatory assets[3]	6,198	9,989
Long-term regulatory assets[3]	72,128	63,970

(1) Includes pre-review and post-review deferred costs, amounts currently in amortization, and interest, net of amounts collected from customers.

(2) Excludes 3.32% of the Front Street site liability, or $0.4 million in 2017 and $0.3 million in 2016, as the OPUC only allows recovery of 96.68% of costs for those sites allocable to Oregon, including those that historically served only Oregon customers.

(3) Environmental costs relate to specific sites approved for regulatory deferral by the OPUC and WUTC. In Oregon, we earn a carrying charge on cash amounts paid, whereas amounts accrued but not yet paid do not earn a carrying charge until expended. We also accrue a carrying charge on insurance proceeds for amounts owed to customers. In Washington, a carrying charge related to deferred amounts will be determined in a future proceeding. Current environmental costs represent remediation costs management expects to collect from customers in the next 12 months. Amounts included in this estimate are still subject to a prudence and earnings test review by the OPUC and do not include the $5 million tariff rider. The amounts allocable to Oregon are recoverable through utility rates, subject to an earnings test.

ENVIRONMENTAL EARNINGS TEST. To the extent the utility earns at or below its authorized Return of Equity (ROE), remediation expenses and interest in excess of the $5.0 million tariff rider and $5.0 million insurance proceeds are recoverable through the SRRM. To the extent the utility earns more than its authorized ROE in a year, the utility is required to cover environmental expenses and interest on expenses greater than the $10.0 million with those earnings that exceed its authorized ROE.

Under the 2015 Order, the OPUC will revisit the deferral and amortization of future remediation expenses, as well as the treatment of remaining insurance proceeds three years from the original Order, or earlier if we gain greater certainty about our future remediation costs, to consider whether adjustments to the mechanism may be appropriate.

WASHINGTON DEFERRAL. In Washington, cost recovery and carrying charges on amounts deferred for costs associated with services provided to Washington customers will be determined in a future proceeding.

Legal Proceedings

NW Natural is subject to claims and litigation arising in the ordinary course of business. Although the final outcome of any of these legal proceedings cannot be predicted with certainty, including the matter described below, we do not expect that the ultimate disposition of any of these matters will have a material effect on our financial condition, results of operations, or cash flows.

OREGON STEEL MILLS SITE. In 2004, NW Natural was served with a third-party complaint by the Port of Portland (the Port) in a Multnomah County Circuit Court case, Oregon Steel Mills, Inc. v. The Port of Portland. The Port alleges that in the 1940s and 1950s petroleum wastes generated by our predecessor, Portland Gas & Coke Company, and 10 other third-party defendants, were disposed of in a waste oil disposal facility operated by the United States or Shaver Transportation Company on property then owned by the Port and now owned by Evraz Oregon Steel Mills. The complaint seeks contribution for unspecified past remedial action costs incurred by the Port regarding the former waste oil disposal facility as well as a declaratory judgment allocating liability for future remedial action costs. No date has been set for trial. In August 2017, the case was stayed pending outcome of the Portland Harbor allocation process or other remediation. Although the final outcome of this proceeding cannot be predicted with certainty, we do not expect the ultimate disposition of this matter will have a material effect on our financial condition, results of operations, or cash flows.

For additional information regarding other commitments and contingencies, see Note 14.

Name of Respondent	This Report is:	Date of Report	Year of Report
	(1) ☒ An Original	(Mo, Da, Yr)	
Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION

Line No.	Item (a)	Total (b)
1	UTILITY PLANT	
2	In Service	
3	Plant in Service (Classified)	2,615,339,576
4	Property Under Capital Leases	—
5	Plant Purchased or Sold	—
6	Completed Construction not Classified	340,419,131
7	Experimental Plant Unclassified	—
8	TOTAL Utility Plant (Total of lines 3 thru 7)	2,955,758,707
9	Leased to Others	—
10	Held for Future Use	970,068
11	Construction Work in Progress	159,923,802
12	Acquisition Adjustments	—
13	TOTAL Utility Plant (Total of lines 8 thru 12)	3,116,652,577
14	Accumulated Provisions for Depreciation, Amortization, & Depletion	1,302,494,942
15	Net Utility Plant (Enter Total of line 13 less 14)	1,814,157,635
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION	
17	In Service:	
18	Depreciation	1,250,333,767
19	Amortization and Depl. of Producing Natural Gas Land and Land Rights	—
20	Amortization. of Underground Storage Land and Land Rights	28,695
21	Amortization. of Other Utility Plant	81,018,335
22	Salvage Work In Progress	—
23	Less Removal Work In Progress	28,885,855
24	TOTAL In Service (Total of lines 18 thru 22 less line 23)	1,302,494,942
25	Leased to Others	
26	Depreciation	—
27	Amortization and Depletion	—
28	TOTAL Leased to Others (Total of lines 26 and 27)	—
29	Held for Future Use	
30	Depreciation	—
31	Amortization	—
32	TOTAL Held for Future Use (Total of lines 30 and 31)	—
33	Abandonment of Leases (Natural Gas)	—
34	Amortization of Plant Acquisition Adjustment	—
35	TOTAL Accumulated Provisions (Should agree with line 14 above) (Total of lines 24, 28, 32, 33, and 34)	1,302,494,942

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION (Continued)

Electric (c)	Gas (d)	Other (Specify) (e)	Common (f)	Line No.
				1
				2
	2,615,339,576			3
	—			4
	—			5
	340,419,131			6
	—			7
	2,955,758,707			8
	—			9
	970,068			10
	159,923,802			11
	—			12
	3,116,652,577			13
	1,302,494,942			14
	1,814,157,635			15
				16
				17
	1,250,333,767			18
	—			19
	28,695			20
	81,018,335			21
	—			22
	28,885,855			23
	1,302,494,942			24
				25
	—			26
	—			27
	—			28
				29
	—			30
	—			31
	—			32
	—			33
	—			34
	1,302,494,942			35

Gas Plant in Service (Accounts 101, 102, 103, and 106

1. Report below the original cost of gas plant in service according to the prescribed accounts.

2. In addition to Account 101, Gas Plant in Service (Classified), this page and the next include Account 102, Gas Plant Purchased or Sold, Account 103, Experimental Gas Plant Unclassified, and Account 106, Completed Construction Not Classified-Gas.

3. Include in column (c) and (d), as appropriate corrections of additions and retirements for the current or preceding year.

4. Enclose in parenthesis credit adjustments of plant accounts to indicate the negative effect of such accounts.

5. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c).Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d) reversals of tentative distributions of prior year's unclassified retirements. Attach supplemental statement showing the account distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Account 101 and 106 will avoid serious omissions of respondent's reported amount for plant actually in service at end of year.

6. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102. In showing the clearance of Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits to primary account classifications.

7. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirements of these pages.

8. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchaser, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give date of such filing.

SEE FOLLOWING PAGES

ACCOUNT SUMMARY BY FUNCTIONAL CLASS

NW Natural

						Period Beginning:	January 2017
						Period Ending:	December 2017
Functional Class		Beginning					Ending
FERC Plant Account		Balance	Additions	Retirements	Transfers	Adjustments	Balance*
UTILITY							
Intangible Plant							
301	ORGANIZATION	1,174	—	—	—	—	1,174
302	FRANCHISES & CONSENTS	83,621	—	—	—	—	83,621
303.1	COMPUTER SOFTWARE	62,412,418	5,571,243	—	—	13,901	67,997,562
303.2	CUSTOMER INFORMATION SYSTEM	32,348,168	—	—	—	—	32,348,168
303.3	INDUSTRIAL & COMMERCIAL BIL	4,146,951	—	—	—	—	4,146,951
303.4	CRMS	682,893	—	—	—	—	682,893
303.5	POWERPLANT SOFTWARE	—	—	—	—	—	—
	Intangible Plant Subtotal*	99,675,225	5,571,243	—	—	13,901	105,260,369
Production Plant - Oil Gas							
304.1	LAND	24,998	—	—	—	—	24,998
305.2	P P O G STRU & IMPR-SEWER S	—	—	—	—	—	—
305.5	P P O G STRU & IMPR-OTHER Y	13,156	—	—	—	—	13,156
312.3	P P O G FUEL HANDLING AND S	—	—	—	—	—	—
318.3	P P O G LIGHT OIL REFINING	144,896	—	—	—	—	144,896
318.5	P P O G TAR PROCESSING	243,551	—	—	—	—	243,551
325	NATURAL GAS PROD AND GATHER	—	—	—	—	—	—
327	NATURAL GAS PROD & GATHERIN	—	—	—	—	—	—
328	NATURAL GAS PROD AND GATHER	—	—	—	—	—	—
331	NATURAL GAS PROD & GATHERIN	—	—	—	—	—	—
332	NATURAL GAS PROD & GATHERIN	—	—	—	—	—	—
333	NATURAL GAS PROD & GATHERIN	—	—	—	—	—	—
334	NATURAL GAS PROD & GATHERIN	—	—	—	—	—	—
	Production Plant - Oil Gas Subtotal*	426,601	—	—	—	—	426,601
Production Plant - Other							
305.11	GAS PRODUCTION - COTTAGE G	8,320	—	—	—	—	8,320
305.17	STRUCTURES MIXING STATION	46,587	—	—	—	—	46,587
311	P P OTHER-LIQUEFIED PETROLE	—	—	—	—	—	—
311.4	P P OTHER-L P G GRANGER	—	—	—	—	—	—
311.7	LIQUIFIED GAS EQUIPMENT COO	4,033	—	—	—	—	4,033
311.8	LIQUIFIED GAS EQUIPMENT LIN	4,209	—	—	—	—	4,209
319	GAS MIXING EQUIPMENT GASCO	185,448	—	—	—	—	185,448
	Production Plant - Other Subtotal*	248,597	—	—	—	—	248,597

ACCOUNT SUMMARY BY FUNCTIONAL CLASS

NW Natural

Period Beginning: January 2017

Period Ending: December 2017

Functional Class FERC Plant Account		Beginning Balance	Additions	Retirements	Transfers	Adjustments	Ending Balance*
UTILITY							
Natural Gas Underground Storage							
350.1	LAND	106,549	—	—	—	—	106,549
350.2	RIGHTS-OF-WAY	109,625	—	—	—	—	109,625
351	STRUCTURES AND IMPROVEMENTS	7,208,245	173,825	—	—	—	7,382,069
352	WELLS	20,047,076	—	—	—	—	20,047,076
352.1	STORAGE LEASEHOLD & RIGHTS	3,938,491	—	—	—	—	3,938,491
352.2	RESERVOIRS	7,272,553	—	—	—	—	7,272,553
352.3	NON-RECOVERABLE NATURAL GAS	6,440,890	—	—	—	—	6,440,890
353	LINES	6,552,220	—	—	—	—	6,552,220
354	COMPRESSOR STATION EQUIPMENT	31,351,812	904	—	—	—	31,352,716
355	MEASURING / REGULATING EQUIPM	7,284,199	123,928	—	—	—	7,408,127
356	PURIFICATION EQUIPMENT	297,363	—	—	—	—	297,363
357	OTHER EQUIPMENT	1,332,029	—	—	—	—	1,332,029
	Natural Gas Underground Storage Subtotal*	91,941,052	298,657	—	—	—	92,239,708
Local Storage Plant							
360.11	LAND - LNG LINNTON	83,598	—	—	—	—	83,598
360.12	LAND - LNG NEWPORT	536,675	—	—	—	—	536,675
360.2	LAND - OTHER	106,557	—	—	—	—	106,557
361.11	STRUCTURES & IMPROVEMENTS	5,079,620	14,239	(25,020)	—	—	5,068,838
361.12	STRUCTURES & IMPROVEMENTS	7,562,817	12,958,841	(488,187)	—	(10,019,710)	10,013,761
361.2	STRUCTURES & IMPROVEMENTS -	26,757	—	—	—	—	26,757
362.11	GAS HOLDERS - LNG LINNTON	4,333,166	222,898	—	—	—	4,556,064
362.12	GAS HOLDERS - LNG NEWPORT	5,773,903	153,200	—	—	—	5,927,104
362.2	GAS HOLDERS - LNG OTHER	1,600	—	—	—	—	1,600
363.11	LIQUEFACTION EQUIP. - LINN	3,235,223	100,998	(27,318)	—	—	3,308,902
363.12	LIQUEFACTION EQUIP - NEWPO	7,240,152	40,366	(76,582)	—	3,521,246	10,725,181
363.21	VAPORIZING EQUIP - LINNTON	2,683,660	3,009,406	(316,443)	—	(918,006)	4,458,618
363.22	VAPORIZING EQUIP - NEWPORT	3,677,348	3,429,098	(2,328,558)	—	(1,038,074)	3,739,813
363.31	COMPRESSOR EQUIP - LINNTON	180,903	—	—	—	—	180,903
363.32	COMPRESSOR EQUIPMENT - NE	3,512,434	79,270	—	—	775,010	4,366,715
363.41	MEASURING & REGULATING EQU	1,248,620	285,146	—	—	918,006	2,451,772
363.42	MEASURING & REGULATING EQU	113,414	3,565,809	(9,934)	—	6,620,606	10,289,895
363.5	CNG REFUELING FACILITIES	3,051,295	—	—	—	—	3,051,295
363.6	LNG REFUELING FACILITIES	739,473	—	—	—	—	739,473
	Local Storage Plant Subtotal*	49,187,216	23,859,271	(3,272,043)	—	(140,921)	69,633,523

ACCOUNT SUMMARY BY FUNCTIONAL CLASS

NW Natural

Period Beginning: January 2017
Period Ending: December 2017

Functional Class FERC Plant Account		Beginning Balance	Additions	Retirements	Transfers	Adjustments	Ending Balance*
UTILITY							
Transmission Plant							
365.1	LAND	89,772	—	—	—	—	89,772
365.2	LAND RIGHTS	6,455,177	—	—	—	—	6,455,177
366.3	STRUCTURES & IMPROVEMENTS -	1,546,073	—	—	—	—	1,546,073
367	MAINS	151,336,318	3,190,254	—	—	—	154,526,573
367.21	NORTH MIST TRANSMISSION LI	1,994,582	—	—	—	—	1,994,582
367.22	SOUTH MIST TRANSMISSION LI	14,949,264	—	—	—	—	14,949,264
367.23	SOUTH MIST TRANSMISSION LI	34,881,341	—	—	—	—	34,881,341
367.24	11.7M S MIST TRANS LINE	17,466,182	—	—	—	—	17,466,182
367.25	12M NORTH S MIST TRANS	18,613,651	—	—	—	—	18,613,651
367.26	38M NORTH S MIST TRANS	68,232,676	—	—	—	—	68,232,676
368	TRANSMISSION COMPRESSOR	—	—	—	—	—	—
369	MEASURING & REGULATE STATION	3,969,549	—	—	—	—	3,969,549
370	COMMUNICATION EQUIPMENT	—	—	—	—	—	—
	Transmission Plant Subtotal*	319,534,586	3,190,254	—	—	—	322,724,840
Distribution Plant							
374.1	LAND	85,773	—	—	—	—	85,773
374.2	LAND RIGHTS	1,883,762	—	—	—	—	1,883,762
375	STRUCTURES & IMPROVEMENTS	1,398,111	19,662	—	—	—	1,417,773
376.11	MAINS < 4"	572,463,038	19,213,883	(175,814)	—	42,383	591,543,490
376.12	MAINS 4" & >	523,414,094	22,818,322	(217,371)	—	49,168	546,064,213
377	COMPRESSOR STATION EQUIPMENT	818,380	—	—	—	—	818,380
378	MEASURING & REG EQUIP - GENER	33,450,398	962,374	—	—	—	34,412,772
379	MEASURING & REG EQUIP - GATE	7,514,713	3,330,868	—	—	—	10,845,581
380	SERVICES	737,144,683	32,523,179	(1,162,235)	—	35,469	768,541,097
381	METERS	86,560,251	3,120,188	(696,854)	—	(1,419,146)	87,564,438
381.1	METERS (ELECTRONIC)	1,696,938	—	—	—	—	1,696,938
381.2	ERT (ENCODER RECEIVER TRANS	40,510,319	1,475,062	(403,962)	—	1,419,146	43,000,565
382	METER INSTALLATIONS	59,388,747	3,115,014	(1,694,704)	—	—	60,809,058
382.1	METER INSTALLATIONS (ELECTR	481,020	—	—	—	—	481,020
382.2	ERT INSTALLATION (ENCODER	9,370,149	—	(74,826)	—	—	9,295,324
383	HOUSE REGULATORS	1,678,311	193,613	—	—	—	1,871,924
386	OTHER PROPERTY ON CUSTOMERS P	—	1,100,432	—	—	—	1,100,432
387.1	CATHODIC PROTECTION TESTING	173,859	—	—	—	—	173,859
387.2	CALORIMETERS @ GATE STATIONS	96,424	—	—	—	—	96,424
387.3	METER TESTING EQUIPMENT	72,671	—	—	—	—	72,671
	Distribution Plant Subtotal*	2,078,201,641	87,872,597	(4,425,765)	—	127,020	2,161,775,493

ACCOUNT SUMMARY BY FUNCTIONAL CLASS

NW Natural

Period Beginning: January 2017

Period Ending: December 2017

Functional Class / FERC Plant Account		Beginning Balance	Additions	Retirements	Transfers	Adjustments	Ending Balance*
UTILITY							
General Plant							
389	LAND	10,767,907	—	—	—	—	10,767,907
390	STRUCTURES & IMPROVEMENTS	59,813,693	562,165	—	—	—	60,375,857
390.1	SOURCE CONTROL PLANT	18,840,271	457,371	—	—	—	19,297,642
391.1	OFFICE FURNITURE & EQUIPMEN	10,863,697	616,407	—	—	—	11,480,104
391.2	COMPUTERS	21,619,782	8,872,600	(4,117,001)	—	—	26,375,380
391.3	ON SITE BILLING	—	—	—	—	—	—
391.4	CUSTOMER INFORMATION SYSTEM	—	—	—	—	—	—
392	TRANSPORTATION EQUIPMENT	38,658,205	5,641,036	(1,737,627)	—	—	42,561,613
393	STORES EQUIPMENT	119,406	—	—	—	—	119,406
394	TOOLS - SHOP & GARAGE EQUIPUI	9,887,393	1,972,557	—	—	—	11,859,950
395	LABORATORY EQUIPMENT	68,293	—	—	—	—	68,293
396	POWER OPERATED EQUIPMENT	9,040,188	1,446,523	(441,739)	—	—	10,044,972
397	GEN PLANT-COMMUNICATION EQU	88,322	—	—	—	—	88,322
397.1	MOBILE	475,621	—	—	—	—	475,621
397.2	OTHER THAN MOBILE & TELEMET	1,690,854	—	—	—	—	1,690,854
397.3	TELEMETERING - OTHER	4,712,298	—	—	—	—	4,712,298
397.4	TELEMETERING - MICROWAVE	1,646,795	1,206,002	—	—	—	2,852,797
397.5	TELEPHONE EQUIPMENT	490,764	2	—	—	—	490,767
398	GEN PLANT-MISCELLANEOUS EQU	—	—	—	—	—	—
398.1	PRINT SHOP	83,249	—	—	—	—	83,249
398.2	KITCHEN EQUIPMENT	12,812	—	—	—	—	12,812
398.3	JANITORIAL EQUIPMENT	14,873	—	—	—	—	14,873
398.4	INSTALLED IN LEASED BUILDINGS	10,120	—	—	—	—	10,120
398.5	OTHER MISCELLANEOUS EQUIPMENT	66,739	—	—	—	—	66,739
	General Plant Subtotal*	188,971,283	20,774,661	(6,296,367)	—	—	203,449,576
	Utility Property Grand Total*	2,828,186,199	141,566,683	(13,994,175)	—	—	2,955,758,707

ACCOUNT SUMMARY BY FUNCTIONAL CLASS

NW Natural

Period Beginning: January 2017

Period Ending: December 2017

Functional Class FERC Plant Account		Beginning Balance	Additions	Retirements	Transfers	Adjustments	Ending Balance*
NON-UTILITY							
Intangible Plant							
303.1	COMPUTER SOFTWARE	163,357	—	—	—	—	163,357
303.2	CUSTOMER INFORMATION SYSTEM	61,429	—	—	—	—	61,429
Non Utility	Intangible Plant Subtotal*	224,786	—	—	—	—	224,786
Natural Gas Underground Storage							
352	WELLS	16,940,451	—	—	—	—	16,940,451
352.1	STORAGE LEASEHOLD & RIGHTS	1,020	—	—	—	—	1,020
352.2	RESERVOIRS	3,561,501	—	—	—	—	3,561,501
353	LINES	1,649,744	—	—	—	—	1,649,744
354	COMPRESSOR STATION EQUIPMENT	13,152,395	147,448	—	—	—	13,299,843
355	MEASURING / REGULATING EQUIPM	8,826,808	49,922	—	—	—	8,876,730
357	OTHER EQUIPMENT	63,256	—	—	—	—	63,256
Non Utility	Natural Gas Underground Storage Subtotal*	44,195,176	197,369	—	—	—	44,392,546
Transmission Plant							
368	TRANSMISSION COMPRESSOR	7,723,454	—	—	—	—	7,723,454
Non Utility	Transmission Plant Subtotal*	7,723,454	—	—	—	—	7,723,454
Distribution Plant							
376.12	MAINS 4" & >	878,618	—	—	—	—	878,618
Non Utility	Distribution Plant Subtotal*	878,618	—	—	—	—	878,618
General Plant							
389	LAND	438,739	—	—	—	—	438,739
390	STRUCTURES & IMPROVEMENTS	231,688	6,781	—	—	—	238,469
Non Utility	General Plant Subtotal*	670,427	6,781	—	—	—	677,208

ACCOUNT SUMMARY BY FUNCTIONAL CLASS

NW Natural

Period Beginning: January 2017

Period Ending: December 2017

Functional Class / FERC Plant Account		Beginning Balance	Additions	Retirements	Transfers	Adjustments	Ending Balance*
NON-UTILITY							
Non Utility Other							
121.1	NON-UTIL PROP-DOCK	1,946,033	—	—	—	—	1,946,033
121.2	NON-UTIL PROP-LAND	125,102	—	—	—	—	125,102
121.3	NON-UTIL PROP-OIL ST	3,669,978	965,202	—	—	—	4,635,180
121.7	NON-UTIL PROP-APPL CENTER	61,113	3,793	—	—	—	64,906
121.8	NON-UTIL PROP-STORAGE	96,038	—	—	—	—	96,038
Non Utility	Other*	5,898,264	968,995	—	—	—	6,867,259
	Non Utility Property Grand Total*	59,590,725	1,173,146	—	—	—	60,763,871

Non Utility Property Summary		
	Non Utility Property Grand Total	60,763,871
121117	Gas Stored Underground - St. Helens	4,233,414
121707-8	Construction Work in Progress Non Utility	4,121,881
Balance Sheet Total for Non Utility Property*		69,119,165

* May not foot due to rounding.

Name of Respondent	This Report is:	Date of Report	Year of Report
	(1) ☒ An Original	(Mo, Da, Yr)	
Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

Gas Property And Capacity Leased From Others

1. Report below the information called for concerning gas property and capacity leased from others for gas operations.

2. For all leases in which the average annual lease payment over the initial term of the lease exceeds $500,000, describe in column (c), if applicable: the property or capacity leased. Designate associated companies with an asterisk in column (b).

Line No.	Name of Lessor (a)	* (b)	Description of Lease (c)	Lease Payments for Current Year (d)
1	Northwest Pipeline		Pipeline Capacity	50,470,607
2	TMC "Nova and ANG"		Pipeline Capacity	11,321,484
3	Fortis BC		Pipeline Capacity	6,829,873
4	TransCanada "Gas Trans NW"		Pipeline Capacity	5,063,954
5	Tenaska Marketing Cdn. "Southern Crossing"		Pipeline Capacity	3,814,175
6	One Pacific Square LLC		Corporate Headquarter Building	4,424,361
7	Tenaska Marketing Ventures		Pipeline Capacity	2,014,768
8	J Aron		Pipeline Capacity	679,320
9	International Paper		Pipeline Capacity	478,880
10	KB Pipeline		Pipeline Capacity	224,258
11	Coos County Pipeline		Pipeline Capacity	362,993
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34				
35	**Total**			**85,684,673**

Name of Respondent	This Report is:	Date of Report	Year of Report
	(1) ☒ An Original	(Mo, Da, Yr)	
Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

Gas Plant Held for Future Use (Account 105)

1. Report separately each property held for future use at end of the year having an original cost of $1,000,000 or more. Group property held for future use.

2. For property having an original cost of $1,000,000 or more previously used in utility operations, now held for future use, give in column (a),in addition to other required information, the date that utility use of such property was discontinued, and the date the original cost was transferred to Account 105.

Line No.	Description and Location of Property (a)	Date Originally Included in this account (b)	Date Expected to be Used in Utility Service (c)	Balance at End of Year (d)
1	Underground Storage	07/2009	Undetermined	127,921
2	Easement	11/2011	Undetermined	136,720
3	Willamette River Crossing - Engineering Costs	05/2015	Undetermined	705,427
4				
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34				
35	**Total**			**970,068**

Construction Work in Progress - Gas (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (Account 107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstration (see Account 107 of the Uniform System of Accounts).
3. Minor projects (less than $1,000,000) may be grouped.

Line No.	Description of Project (a)	Construction Work in Progress - Gas (Account 107) (b)	Estimated Additional Cost of Project (c)
1	North Mist Expansion Project	113,165,780	18,834,220
2	Mains and Service Jobs	16,070,135	18,159,957
3	Other	14,069,708	5,260,011
4	Misc IS Projects	13,770,451	6,312,140
5	Misc Facilities Projects	1,447,556	30,522,645
6	Portland LNG Readiness	1,047,455	2,663,025
7	Newport LNG Readiness	352,717	3,984,559
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34			
35	**Total**	**159,923,802**	**85,736,557**

GENERAL DESCRIPTION OF CONSTRUCTION OVERHEAD PROCEDURE

1. For each construction overhead explain: (a) the nature and extent of work,etc., the overhead charges are intended to cover, (b) the general procedure for determining the amount capitalized, (c) the method of distribution to construction jobs, (d) whether different rates are applied to different types of construction, (e) basis of differentiation in rates for different types of construction, and (f) whether the overhead is directly or indirectly assigned.

2. Show below the computation of allowance for funds used during construction rates, in accordance with the provisions of Gas Plant Instructions 3 917) of the Uniform System of Accounts.

3. Where a net-of-tax rate for borrowed funds is used, show the appropriate tax effect adjustment to the computations below in a manner that clearly indicates the amount of reduction in the gross rate for tax effects.

GENERAL DESCRIPTION OF CONSTRUCTION OVERHEAD PROCEDURE

1. a) Engineering Department overhead covers transmission and distribution system planning, design work, drafting and platting of construction work.

Distribution Department overhead covers transmission and distribution system work scheduling, field supervision and processing of work completed.

Administrative work overhead includes Purchasing, Accounting and general office expense.

General Services Department overhead covers planning and supervision of general plant improvements and facilities.

b) Charges during the year are segregated into overhead accounts based on the proportion of activity devoted to construction work.

c) Construction Overheads are being charged to individual work orders based upon overhead rates for different types of projects. Rates are determined by type of project using the annual capital budget and annual construction overhead budget.

d) Different rates are applied to different types of construction based on the annual capital budget for each type of plant.

e) Actual construction overhead rates applied to types of work in: 2017

a. Production, Storage, Transmission and Distribution plant	44%
b. Meters	75%
c. General Plant	19%
d. Non-Utility Property	1%

f) Direct assignment of construction overhead capitalized during: 2017
47,266,395

2. ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION (AFUDC)

AFUDC is applied to previous month's ending balance plus half of current month's expenditures of Construction Work in Progress (CWIP).

3. N/A

GENERAL DESCRIPTION OF CONSTRUCTION OVERHEAD PROCEDURE (CONTINUED)

COMPUTATION OF ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION RATES

1. For Line (5), column (d) below, enter the rate granted in the last rate proceeding. If not available, use the average rate earned during the preceding 3 years.

2. Identify, in a footnote, the specific entity used as the source for the capital structure figures.

3. Indicate, in a footnote, if the reported rate of return is one that has been approved in a rate case, black-box settlement rate, or an actual three-year average rate.

Line No.	Title (a)	Amount (b)	Capitalization Ration (percent) (c)	Cost Rate Percentage (d)
	(1) Average Short-Term Debt	S 15,980,639		
	(2) Short-Term Interest			s 4.45%
	(3) Long-Term Debt	D 726,700,000	—	d 5.51%
	(4) Preferred Stock	P —	—	p —%
	(5) Common Equity	C 690,375,893	—	c 9.50%
	(6) Total Capitalization	—	100.00%	
	(7) Average Construction Work in Progress	W 115,659,642		
2.	Gross Rates for Borrowed Funds s(S/W)+d[(D/(D+P+C))(1-(S/W)]		3.05%	
3.	Rate for Other Funds [1-(S/W)] [p(P/(D+P+C)+c(C/(D+P+C)]		3.99%	
4.	Weighted Average Rate Actually Used for the Year			
	a. Rate for Borrowed Funds -		2.69%	
	b. Rate for Other Funds -		2.80%	

NOTE: Capital structure figures are for NW Natural Gas Company and rate of return was approved by the OPUC rate case.

Name of Respondent	This Report is:	Date of Report	Year of Report
	(1) ☒ An Original	(Mo, Da, Yr)	
Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

Accumulated Provision for Depreciation of Gas Utility Plant (Account 108)

1. Explain in a footnote any important adjustments during year.

2. Explain in a footnote any difference between the amount for book cost of plant retired, line 10, column (c), and that reported for gas plant in service, page 204-209, column (d), excluding retirements of nondepreciable property.

3. The provisions of Account 108 in the Uniform System of Accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.

4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

5. At lines 7 and 14, add rows as necessary to report all data. Additional rows should be numbered in sequence, e.g., 7.01, 7.02, etc.

SEE FOLLOWING PAGES

RESERVE BALANCES AND ACTIVITY BY FUNCTIONAL CLASS

NW NATURAL

Period Beginning: January 2017

Period Ending: December 2017

Functional Class FERC Plant Account		Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Loss/(Gain)	Ending Reserve*
UTILITY									
Intangible Plant									
301	ORGANIZATION	—	—	—	—	—	—	—	—
302	FRANCHISES & CONSENTS	—	—	—	—	—	—	—	—
303.1	COMPUTER SOFTWARE	23,269,448	2,791,161	—	—	—	154	—	26,060,764
303.2	CUSTOMER INFORMATION SYSTEM	32,348,168	—	—	—	—	—	—	32,348,168
303.3	INDUSTRIAL & COMMERCIAL BIL	4,146,951	—	—	—	—	—	—	4,146,951
303.4	CRMS	683,689	(797)	—	—	—	—	—	682,893
303.5	POWERPLANT SOFTWARE	—	—	—	—	—	—	—	—
	Intangible Plant Subtotal*	60,448,256	2,790,365	—	—	—	154	—	63,238,775
Production Plant - Oil Gas									
304.1	LAND	—	—	—	—	—	—	—	—
305.2	P P O G STRU & IMPR-SEWER S	—	—	—	—	—	—	—	—
305.5	P P O G STRU & IMPR-OTHER Y	13,814	—	—	—	—	—	—	13,814
312.3	P P O G FUEL HANDLING AND S	—	—	—	—	—	—	—	—
318.3	P P O G LIGHT OIL REFINING	152,141	—	—	—	—	—	—	152,141
318.5	P P O G TAR PROCESSING	255,729	—	—	—	—	—	—	255,729
325	NATURAL GAS PROD AND GATHER	—	—	—	—	—	—	—	—
327	NATURAL GAS PROD & GATHERIN	—	—	—	—	—	—	—	—
328	NATURAL GAS PROD AND GATHER	—	—	—	—	—	—	—	—
331	NATURAL GAS PROD & GATHERIN	—	—	—	—	—	—	—	—
332	NATURAL GAS PROD & GATHERIN	—	—	—	—	—	—	—	—
333	NATURAL GAS PROD & GATHERIN	—	—	—	—	—	—	—	—
334	NATURAL GAS PROD & GATHERIN	—	—	—	—	—	—	—	—
	Production Plant - Oil Gas Subtotal*	421,683	—	—	—	—	—	—	421,683
Production Plant - Other									
305.11	GAS PRODUCTION - COTTAGE G	8,736	—	—	—	—	—	—	8,736
305.17	STRUCTURES MIXING STATION	51,246	—	—	—	—	—	—	51,246
311	P P OTHER-LIQUEFIED PETROLE	—	—	—	—	—	—	—	—
311.4	P P OTHER-L P G GRANGER	—	—	—	—	—	—	—	—
311.7	LIQUIFIED GAS EQUIPMENT COO	8,066	—	—	—	—	—	—	8,066
311.8	LIQUIFIED GAS EQUIPMENT LIN	6,585	—	—	—	—	—	—	6,585
319	GAS MIXING EQUIPMENT GASCO	194,720	—	—	—	—	—	—	194,720
	Production Plant - Other Subtotal*	269,353	—	—	—	—	—	—	269,353

Period Beginning: January 2017
Period Ending: December 2017

Functional Class FERC Plant Account		Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Loss/(Gain)	Ending Reserve*
UTILITY									
Natural Gas Underground Storage									
350.1	LAND	—	—	—	—	—	—	—	—
350.2	RIGHTS-OF-WAY	26,919	1,776	—	—	—	—	—	28,695
351	STRUCTURES AND IMPROVEMENTS	2,665,916	123,910	—	—	—	—	—	2,789,826
352	WELLS	11,390,537	414,974	—	—	—	—	—	11,805,512
352.1	STORAGE LEASEHOLD & RIGHTS	1,593,616	76,801	—	—	—	—	—	1,670,417
352.2	RESERVOIRS	2,384,777	146,178	—	—	—	—	—	2,530,955
352.3	NON-RECOVERABLE NATURAL GAS	3,319,796	121,089	—	—	—	—	—	3,440,885
353	LINES	3,041,105	134,967	—	—	—	—	—	3,176,072
354	COMPRESSOR STATION EQUIPMENT	17,881,027	848,770	—	—	—	—	—	18,729,797
355	MEASURING / REGULATING EQUIPM	4,424,715	158,994	—	—	—	—	—	4,583,709
356	PURIFICATION EQUIPMENT	225,070	7,375	—	—	—	—	—	232,445
357	OTHER EQUIPMENT	827,385	30,370	—	—	—	—	—	857,756
	Natural Gas Underground Storage Subtotal*	47,780,863	2,065,204	—	—	—	—	—	49,846,067
Local Storage Plant									
360.11	LAND - LNG LINNTON	—	—	—	—	—	—	—	—
360.12	LAND - LNG NEWPORT	—	—	—	—	—	—	—	—
360.2	LAND - OTHER	—	—	—	—	—	—	—	—
361.11	STRUCTURES & IMPROVEMENTS	2,189,212	276,314	(25,020)	—	—	—	—	2,440,507
361.12	STRUCTURES & IMPROVEMENTS	2,477,560	393,476	(488,187)	—	—	(104,623)	—	2,278,225
361.2	STRUCTURES & IMPROVEMENTS -	10,959	466	—	—	—	—	—	11,425
362.11	GAS HOLDERS - LNG LINNTON	2,241,345	102,509	—	—	—	—	—	2,343,855
362.12	GAS HOLDERS - LNG NEWPORT	5,578,002	157,571	—	—	—	—	—	5,735,573
362.2	GAS HOLDERS - LNG OTHER	1,193	21	—	—	—	—	—	1,213
363.11	LIQUEFACTION EQUIP. - LINN	2,495,345	93,732	(27,318)	—	—	—	—	2,561,759
363.12	LIQUEFACTION EQUIP - NEWPO	7,119,569	67,826	(76,582)	—	—	39,178	—	7,149,990
363.21	VAPORIZING EQUIP - LINNTON	2,662,282	55,948	(316,443)	—	—	(5,293)	—	2,396,494
363.22	VAPORIZING EQUIP - NEWPORT	2,615,653	3,794	(2,328,558)	—	—	(156)	—	290,733
363.31	COMPRESSOR EQUIP - LINNTON	206,897	—	—	—	—	—	—	206,897
363.32	COMPRESSOR EQUIPMENT - NE	367,637	177,133	—	—	—	8,596	—	553,366
363.41	MEASURING & REGULATING EQU	604,762	526	—	—	—	5,293	—	610,581
363.42	MEASURING & REGULATING EQU	118,309	26,008	(9,934)	—	—	55,772	—	190,155
363.5	CNG REFUELING FACILITIES	1,360,531	31,733	—	—	—	—	—	1,392,264
363.6	LNG REFUELING FACILITIES	739,473	—	—	—	—	—	—	739,473
	Local Storage Plant Subtotal*	30,788,729	1,387,056	(3,272,043)	—	—	(1,232)	—	28,902,511

RESERVE BALANCES AND ACTIVITY BY FUNCTIONAL CLASS
NW NATURAL

Period Beginning: January 2017
Period Ending: December 2017

Functional Class / FERC Plant Account		Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Loss/(Gain)	Ending Reserve*
UTILITY									
Transmission Plant									
365.1	LAND	—	—	—	—	—	—	—	—
365.2	LAND RIGHTS	1,886,332	122,003	—	—	—	—	—	2,008,335
366.3	STRUCTURES & IMPROVEMENTS -	298,976	30,148	—	—	—	—	—	329,124
367	MAINS	27,866,944	4,685,280	—	—	—	—	—	32,552,224
367.21	NORTH MIST TRANSMISSION LI	1,079,882	50,054	—	—	—	—	—	1,129,936
367.22	SOUTH MIST TRANSMISSION LI	10,301,352	367,672	—	—	—	—	—	10,669,024
367.23	SOUTH MIST TRANSMISSION LI	12,757,392	931,147	—	—	—	—	—	13,688,539
367.24	11.7M S MIST TRANS LINE	5,271,948	452,281	—	—	—	—	—	5,724,229
367.25	12M NORTH S MIST TRANS	5,307,360	485,717	—	—	—	—	—	5,793,077
367.26	38M NORTH S MIST TRANS	19,647,514	1,773,685	—	—	—	—	—	21,421,198
368	TRANSMISSION COMPRESSOR	(9)	—	—	—	—	—	—	(9)
369	MEASURING & REGULATE STATION	1,444,979	106,379	—	—	—	—	—	1,551,358
370	COMMUNICATION EQUIPMENT	—	—	—	—	—	—	—	—
	Transmission Plant Subtotal*	85,862,668	9,004,366	—	—	—	—	—	94,867,034
Distribution Plant									
374.1	LAND	—	—	—	—	—	—	—	—
374.2	LAND RIGHTS	1,420,339	141,282	—	—	—	—	—	1,561,621
375	STRUCTURES & IMPROVEMENTS	80,809	6,047	—	—	—	—	—	86,857
376.11	MAINS < 4"	311,528,527	14,565,632	(175,814)	(878,723)	9,405	360	—	325,049,387
376.12	MAINS 4" & >	211,230,558	12,926,901	(217,371)	(864,307)	27,222	417	—	223,103,421
377	COMPRESSOR STATION EQUIPMENT	630,397	19,068	—	—	—	—	—	649,465
378	MEASURING & REG EQUIP - GENER	11,523,264	726,592	—	—	—	—	—	12,249,857
379	MEASURING & REG EQUIP - GATE	2,063,027	391,504	—	—	—	—	—	2,454,531
380	SERVICES	388,319,622	20,342,670	(1,162,235)	(1,248,131)	—	301	—	406,252,227
381	METERS	21,812,403	2,020,749	(696,854)	—	—	(56,230)	—	23,080,068
381.1	METERS (ELECTRONIC)	1,313,599	339,434	—	—	—	—	—	1,653,033
381.2	ERT (ENCODER RECEIVER TRANS	18,712,771	2,737,004	(403,962)	—	—	56,230	—	21,102,043
382	METER INSTALLATIONS	7,264,856	1,423,070	(1,694,704)	—	—	—	—	6,993,222
382.1	METER INSTALLATIONS (ELECTR	52,024	11,490	—	—	—	—	—	63,514
382.2	ERT INSTALLATION (ENCODER	4,922,504	621,461	(74,826)	—	—	—	—	5,469,140
383	HOUSE REGULATORS	216,165	50,367	—	—	—	—	—	266,532
386	OTHER PROPERTY ON CUSTOMERS P	—	—	—	—	—	—	—	—
387.1	CATHODIC PROTECTION TESTING	141,431	956	—	—	—	—	—	142,388
387.2	CALORIMETERS @ GATE STATIONS	96,424	—	—	—	—	—	—	96,424
387.3	METER TESTING EQUIPMENT	72,671	—	—	—	—	—	—	72,671
	Distribution Plant Subtotal*	981,401,393	56,324,229	(4,425,765)	(2,991,160)	36,627	1,078	—	1,030,346,401

RESERVE BALANCES AND ACTIVITY BY FUNCTIONAL CLASS

NW NATURAL

Period Beginning: January 2017

Period Ending: December 2017

Functional Class FERC Plant Account		Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Loss/(Gain)	Ending Reserve*
UTILITY									
General Plant									
389	LAND	437,351	—	—	—	—	—	—	437,351
390	STRUCTURES & IMPROVEMENTS	9,465,894	1,171,021	—	—	—	—	—	10,636,914
390.1	SOURCE CONTROL PLANT	3,268,635	1,000,355	—	—	—	—	—	4,268,989
391.1	OFFICE FURNITURE & EQUIPMEN	7,327,274	882,885	—	—	—	—	—	8,210,159
391.2	COMPUTERS	16,146,225	4,188,715	(4,117,001)	—	—	—	—	16,217,939
391.3	ON SITE BILLING	—	—	—	—	—	—	—	—
391.4	CUSTOMER INFORMATION SYSTEM	—	—	—	—	—	—	—	—
392	TRANSPORTATION EQUIPMENT	9,372,980	2,030,014	(1,737,627)	—	223,715	—	—	9,889,082
393	STORES EQUIPMENT	119,406	—	—	—	—	—	—	119,406
394	TOOLS - SHOP & GARAGE EQUIPUI	3,445,724	755,141	—	—	4,706	—	—	4,205,571
395	LABORATORY EQUIPMENT	68,293	—	—	—	—	—	—	68,293
396	POWER OPERATED EQUIPMENT	2,923,748	195,991	(441,739)	—	129,938	—	—	2,807,938
397	GEN PLANT-COMMUNICATION EQU	33,654	6,545	—	—	—	—	—	40,199
397.1	MOBILE	407,625	3,234	—	—	—	—	—	410,859
397.2	OTHER THAN MOBILE & TELEMET	1,690,854	—	—	—	—	—	—	1,690,854
397.3	TELEMETERING - OTHER	2,994,749	3,299	—	—	—	—	—	2,998,047
397.4	TELEMETERING - MICROWAVE	950,261	25,997	—	—	—	—	—	976,258
397.5	TELEPHONE EQUIPMENT	252,246	79,749	—	—	—	—	—	331,995
398	GEN PLANT-MISCELLANEOUS EQU	—	—	—	—	—	—	—	—
398.1	PRINT SHOP	83,249	—	—	—	—	—	—	83,249
398.2	KITCHEN EQUIPMENT	3,612	525	—	—	—	—	—	4,137
398.3	JANITORIAL EQUIPMENT	14,873	—	—	—	—	—	—	14,873
398.4	INSTALLED IN LEASED BUILDINGS	10,120	—	—	—	—	—	—	10,120
398.5	OTHER MISCELLANEOUS EQUIPMENT	66,739	—	—	—	—	—	—	66,739
	General Plant Subtotal*	59,083,510	10,343,472	(6,296,367)	—	358,359	—	—	63,488,973
	Utility Property Grand Total*	1,266,056,456	81,914,691	(13,994,175)	(2,991,160)	394,986	—	—	1,331,380,797

RESERVE BALANCES AND ACTIVITY BY FUNCTIONAL CLASS

NW NATURAL

Period Beginning: January 2017

Period Ending: December 2017

Functional Class FERC Plant Account		Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Loss/(Gain)	Ending Reserve*
NON UTILITY									
Intangible Plant									
303.1	COMPUTER SOFWARE	45,293	7,041	—	—	—	—	—	52,333
303.2	CUSTOMER INFORMATION SYSTEM	42,228	4,275	—	—	—	—	—	46,503
Non Utility	Intangible Plant Subtotal*	87,520	11,316	—	—	—	—	—	98,837
Natural Gas Underground Storage									
352	WELLS	3,599,205	350,667	—	—	—	—	—	3,949,872
352.1	STORAGE LEASEHOLD & RIGHTS	201	20	—	—	—	—	—	221
352.2	RESERVOIRS	807,038	69,449	—	—	—	—	—	876,487
353	LINES	354,310	33,982	—	—	—	—	—	388,292
354	COMPRESSOR STATION EQUIPMENT	4,081,273	381,685	—	—	—	—	—	4,462,958
355	MEASURING / REGULATING EQUIPM	1,919,365	192,570	—	—	—	—	—	2,111,935
357	OTHER EQUIPMENT	10,156	1,442	—	—	—	—	—	11,598
Non Utility	Natural Gas Underground Storage Subtotal*	10,771,549	1,029,816	—	—	—	—	—	11,801,365
Transmission Plant									
368	TRANSMISSION COMPRESSOR	2,087,175	238,655	—	—	—	—	—	2,325,830
Non Utility	Transmission Plant Subtotal*	2,087,175	238,655	—	—	—	—	—	2,325,830
Distribution Plant									
376.12	MAINS 4" & >	214,477	21,258	—	—	—	—	—	235,735
Non Utility	Distribution Plant Subtotal*	214,477	21,258	—	—	—	—	—	235,735
General Plant									
389	LAND	—	—	—	—	—	—	—	—
390	STRUCTURES & IMPROVEMENTS	30,041	4,280	—	—	—	—	—	34,322
Non Utility	General Plant Subtotal*	30,041	4,280	—	—	—	—	—	34,322
Non Utility Other									
121.1	NON-UTIL PROP-DOCK	1,947,067	—	—	—	—	—	—	1,947,067
121.2	NON-UTIL PROP-LAND	—	—	—	—	—	—	—	—
121.3	NON-UTIL PROP-OIL ST	2,223,571	14,159	—	—	—	—	—	2,237,730
121.7	NON-UTIL PROP-APPL CENTER	34,262	4,294	—	—	—	—	—	38,557
121.8	NON-UTIL PROP-STORAGE	(1)	—	—	—	—	—	—	(1)
Non Utility	Other*	4,204,899	18,453	—	—	—	—	—	4,223,352
	Non Utility Property Grand Total*	17,395,661	1,323,778	—	—	—	—	—	18,719,439

RESERVE BALANCES AND ACTIVITY BY FUNCTIONAL CLASS
NW NATURAL

Period Beginning: January 2017
Period Ending: December 2017

Functional Class FERC Plant Account	Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Loss/(Gain)	Ending Reserve*
TOTAL SUMMARY ALL UTILITY DEPRECIATION RESERVES		12/31/2017						
UTILITY								
108010	(42,583,470)							
108011	1,010,037,958							
108012	12,918,116							
108013	(3,099,839)							
108014	(606,910)							
108015	2,936,669							
108100	—							
108102	359,615,455							
108002	(8,386,166)							
108003	63,377							
108004	485,607							
108666	—							
SUBTOTAL*		1,331,380,797						
ADD:								
108001 REMOVAL WORK IN PROCESS		(28,885,855)						
TOTAL UTILITY DEPRECIATION*		1,302,494,942						
TOTAL SUMMARY ALL NON-UTILITY RESERVES DEPRECIATION								
NON UTILITY								
122026	1,034							
122027	4,355,478							
122028	13,671,824							
122029	(531,316)							
122100	—							
122102	1,313,777							
122002	(91,357)							
TOTAL NON UTILITY DEPRECIATION*		18,719,439						

* May not foot due to rounding

GAS STORED (ACCOUNTS 117.1, 117.2, 117.3, 117.4, 164.1, 164.2, AND 164.3)

1. If during the year adjustments were made to the stored gas inventory reported in columns (d), (f), (g) and (h) (such as to correct cumulative inaccuracies of gas measurements), explain in a footnote the reason for the adjustments, the Dth and dollar amount of adjustment, and account charged or credited.

2. Report in column (e) all encroachments during the year upon the volumes designated as base gas, column (b), and system balancing gas, column (c), and gas property recordable in the plant accounts.

3. State in a footnote the basis of segregation of inventory between current and noncurrent portions. Also, state in a footnote the method used to report storage (i.e.., fixed asset method or inventory method).

Line No.	Description (a)	Base Gas (Account 117.1 - 117.8) (b)	System Balancing (Account) (c)	Non Current (Account) (d)	Account (e)	Current Underground (Account 164.21 - 164.23) (f)	LNG (Account 164.21 - 164.23) (g)	LNG (Account 164.35, 164.36) (h)	Total (i)
1	Balance at Beginning of Year	$ 14,133,895	—	—	—	$ 38,746,875	$ 3,989,561	—	$ 56,870,331
2	Gas Delivered to Storage	$ 29,000	—	—	—	$ 21,362,670	$ 1,444,287	—	$ 22,835,957
3	Gas Withdrawn from Storage	$ 27,460	—	—	—	$ 22,415,316	$ 1,692,103	—	$ 24,134,879
4	Other Debits and Credits	4,353,152	—	—	—	$ (4,786,377)	—	—	$ (433,225)
5	Balance at End of Year	$ 18,488,587	$ —	$ —	$ —	$ 32,907,852	$ 3,741,745	$ —	$ 55,138,184
6	Dekatherms	8,007,132	—	—	—	11,068,869	1,215,577	—	$ 20,291,578
7	Amount Per Dekatherm	$ 2.31	$ —	$ —	$ —	$ 2.97	$ 3.08	$ —	$ 2.72

Footnotes:

1. Independent engineering studies are the basis for separation between noncurrent and current inventory.

2. See Notes to Consolidated Financial Statements for method used to report inventories of gas in storage (page 122-A).

3. Amount in column (f) line 4 represents reclass of Working Gas to Cushion Gas due to independent engineering study performed in 2017.

Name of Respondent	This Report is:	Date of Report	Year of Report
	(1) ☒ An Original	(Mo, Da, Yr)	
Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

INVESTMENTS (Accounts 123, 124, 136)

1. Report below investments in Accounts 123, Investments in Associated Companies, 124, Other Investments, and 136, Temporary Cash Investments.

2. Provide a subheading for each account and list thereunder the information called for:

(a) Investment in Securities - List and describe each security owned, giving name of issuer, date acquired and date of maturity. For bonds, also give principal amount, date of issue, maturity, and interest rate. For capital stock (including capital stock of respondent reacquired under a definite plan for resale pursuant to authorization by the Board of Directors, and included in Account 124, Other Investments, state number of shares, class, and series of stock. Minor investments may be grouped by classes. Investments included in Account 136, Temporary Cash Investments, also may be grouped by classes.

(b) Investment Advances - Report separately for each person or company the amounts of loans or investment advances which are properly includable in Account 123. Include advances subject to current repayment in account 145 and 146. With respect to each advance, show whether the advance is a note or open account.

Line No.	Description of Investment (a)	* (b)	Book Cost at Beginning of Year (If book cost is different from cost to respondent, give cost to respondent in a footnote and explain difference.) (c)	Purchases or Additions During the Year (d)
1	Account 123		None	None
2	Account 124			
3	Investment in Life Insurance - 124100-124113[1]		52,719,264	1,467,542
4	Investment in Vancouver Land - 124301		1,862,179	—
5	Total Account 124		54,581,443	1,467,542
6	Account 136 Temporary Cash Investments			
7	Marketable Securities - 136002, 136032		31	978,488,769
8	OLGA Investment Account - 136100		1,025,462	4,432,115
9	OLIEE Investment Account - 136104		2,358,144	3,633,179
10	Smart Inv - 136105		153,284	2,720,892
11	Total Account 136		3,536,921	989,274,955
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1) Purchases and additions represent the change in cash surrender value not additional purchases of life insurance policies.

INVESTMENTS (Accounts 123, 124, 136)

List each note giving date of issuance, maturity date, and specifying whether note is a renewal. Designate any advances due from officers, directors, stockholders, or employees.

3. Designate with an asterisk in column (b) any securities, notes or accounts that were pledged, and in a footnote state the name of pledges and purpose of the pledge.

4. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and cite Commission, date of authorization, and case or docket number.

5. Report in column (h) interest and dividend revenues from investments including such revenues from securities disposed of during the year.

6. In column (i) report for each investment disposed of during the year the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if different from cost) and the selling price thereof, not including any dividend or interest adjustment includible in column (h).

Sales or Other Dispositions During Year (e)	Principal Amount or No. of Shares at End of Year (f)	Book Cost at End of Year of Year (If book cost is different from cost to respondent, give cost to respondent in a footnote and explain difference.) (g)	Revenues for Year (h)	Gain or Loss from Investment Disposed of (i)	Line No.
					1
					2
3,395,250	50,791,556	50,791,556	—	1,025,151	3
—	1,862,179	1,862,179	—	—	4
3,395,250	52,653,735	52,653,735	—	—	5
					6
978,488,800	—	—	—	—	7
4,345,872	1,111,705	1,111,705	—	—	8
4,736,501	1,254,822	1,254,822	—	—	9
2,666,571	207,605	207,605	—	—	10
990,237,744	2,574,132	2,574,132	—	—	11
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Name of Respondent	This Report is:	Date of Report	Year of Report
	(1) ☒ An Original	(Mo, Da, Yr)	
Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

INVESTMENT IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Accounts 123.1, Investments in Subsidiary Companies.

2. Provide a subheading for each company and list thereunder the information called for below. Sub-total by company and give a total in columns (e), (f), (g) and (h).

(a) Investment in Securities - List and describe each security owned. For bonds give also principal amount, date of issue, maturity, and interest rate.

(b) Investment Advances - Report separately the amounts of loans or investment advances which are subject to repayment, but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. List each note giving date of issuance, maturity date, and specifying whether note is a renewal.

3. Report separately the equity in undistributed subsidiary earnings since acquisition. The total in column (e) should equal the amount entered for Account 418.1.

Line No.	Description of Investment (a)	Date Acquired (b)	Date of Maturity (c)	Amount of Investment at Beginning of Year (d)
1	NNG Financial Corporation (Financing and Investments)	6/28/1990		172,077
2	Northwest Natural Energy LLC - (Holding Company)	5/26/2009		159,948,370
3	Northwest Biogas, LLC - (Biodigestor Company)	3/23/2009		27,223
4	Northwest Energy Corporation - (Holding Company)	11/1/2001		130,370,462
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30	**TOTAL Cost of Account 123.1**		**TOTAL**	**290,518,132**

INVESTMENT IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

4. Designate in a footnote any securities, notes, or accounts that were pledged and purpose of pledge.

5. If commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.

6. Report column (f) interest and dividend revenues from investments, including such revenues from securities disposed of during the year.

7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if different from cost) and the selling price thereof, not including interest adjustment includible in column (f).

8. Report on Line 40, column (a) the total cost of Account 123.1

Equity in Subsidiary Earnings for Year	Additional Investment for Year	Amount of Investment at End of Year	Gain or Loss from Investment Disposed of	Line
(e)	(f)	(g)	(h)	No.
19,935	79,998	272,010	—	1
(127,375,960)	1,160,797	33,733,207	—	2
13,330	—	40,553	—	3
(5,911,800)	(6,325,000)	118,133,662	—	4
				5
				6
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(133,254,495)	**(5,084,205)**	**152,179,432**	**—**	30

Prepayments (acct 165), Extraordinary Property Losses (Acct 182.1), Unrecovered Plant and Regulatory Study Costs (Acct 182.2)

PREPAYMENTS (Account 165)

1. Report below the particulars (details) on each prepayment.

Line No.	Nature of Payment (a)	Balance at End of Year (in dollars) (b)
1	Prepaid Taxes	11,084,853
2	Prepaid Rents	468,956
3	Prepaid Insurance	3,015,807
4	Prepaid Interest	—
5	Prepaid Demand Charges	2,697,122
6	Miscellaneous Prepayments	6,691,936
7	TOTAL	23,958,674

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

Line No.	Description of Extraordinary Loss [Include the date of loss, the date of Commission authorization to use Account 182.1 and period of amortization (mo, yr, to mo, yr)] Add rows as necessary to report all data. (a)	Balance at Beginning of Year (b)	Total amount of loss (c)	Losses Recognized During Year (d)	Written off During Year Account charged (e)	Written off During Year Amount (f)	Balance at End of Year (g)
8	None	—	—	—	—	—	—
9							
10							
11							
12							
13							
14							
15							
16	**Total**						—

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (Account 182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs,the date of Commission authorization to use Account 182.2 and period of amortization (mo, yr, to mo, yr)] Add rows as necessary to report all data. Number rows in sequence beginning with the next row number after the last row number used for extraordinary property losses. (a)	Balance at Beginning of Year (b)	Total amount of loss (c)	Losses Recognized During Year (d)	Written off During Year Account charged (e)	Written off During Year Amount (f)	Balance at End of Year (g)
17	None	—	—	—	—	—	—
18							
19							
20							
21							
22							
23							
24							
25	**Total**						—

Name of Respondent	This Report is:	Date of Report	Year of Report
	(1) ☒ An Original	(Mo, Da, Yr)	
Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

OTHER REGULATORY ASSETS (ACCOUNT 182.3)

1.Report below the details called for concerning other regulatory assets which are created through the ratemaking actions of regulatory agencies (and not includable in other accounts).

2.For regulatory assets being amortized, show period of amortization in column (a).

3.Minor items (5% of the Balance at End of Year for account 182.3 or amounts less than $250,000, whichever is less) may be grouped

4.Report separately any "Deferred Regulatory Commission Expenses" that are also reported on pages 350-351, Regulatory Commission Expenses.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Year (b)	Debit (Credit) (c)	Written off During Period Account charged (d)	Written off During Period Amount Recovered (e)	Written off During Period Amount Deemed Unrecoverable (f)	Balance at End of Year (g)
1	Deferred Income Taxes - Utility Plant	43,047,984	(17,394,801)	283	4,378,568	—	21,274,615
2	AFUDC Equity Deferred Taxes	—	933,909		—	—	933,909
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30	Total	43,047,984	(16,460,892)		4,378,568	—	22,208,524

Name of Respondent	This Report is:	Date of Report	Year of Report
	(1) ☒ An Original	(Mo, Da, Yr)	
Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

MISCELLANEOUS DEFERRED DEBITS (Account 186)

1. Report below the details called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show period of amortization in column (a).
3. Minor items (less than $250,000) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	Credits Account Charged (d)	Credits Amount (e)	Balance at End of Year (f)
1	Pension and Other Retirement Benefits	183,034,993	12,176,719		15,387,492	179,824,220
2	Pension Deferral	53,780,201	11,121,453		—	64,901,654
3	Environmental	119,742,638	92,869,642		85,244,646	127,367,634
4	Regulatory Receivable - Environmental	(45,783,623)	4,055,109		7,313,102	(49,041,616)
5	Deferred Derivative Activity	2,228,000	48,391,000		27,258,000	23,361,000
6	Leasehold Improvements Amortized Over Remaining Life	678,271	2,601,715		1,484,926	1,795,060
7	Unbilled Revenue - Amortizations	(2,673,945)	13,639,740		10,960,037	5,758
8	OR - Decoupling	18,947,593	27,957,645		32,970,701	13,934,537
9	OR - Deferred Industrial DSM	6,544,916	9,907,374		7,373,871	9,078,419
10	OR - Warm	423,796	5,948,724		10,300,275	(3,927,755)
11	OR - Pension Withdrawal	6,688,815	10,408		295,658	6,403,565
12	WA - Pension Withdrawal	772,217	1,201		34,134	739,284
13	WA - Energy Efficiency	3,382,696	4,524,047		4,169,307	3,737,436
14	WA - Low Income	470,948	806,635		941,061	336,522
15	Other	332,199	6,065,828		5,781,582	616,445
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29						
30	Total	348,569,715	240,077,240		209,514,792	379,132,163

Name of Respondent	This Report is:	Date of Report	Year of Report
	(1) ☒ An Original	(Mo, Da, Yr)	
Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

Accumulated Deferred Income Taxes (Account 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. At Other (specify), include deferrals relating to other income and deductions.
3. Provide in a footnote a summary of the type and amount of deferred income taxes reported in the beginning-of-year and end-of-year balances for deferred income taxes that the respondent estimates could be included in the development of jurisdictional recourse rates.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Changes During Year Amounts Debited to Account 410.1 (c)	Changes During Year Amounts Credited to Account 411.1 (d)
1	Account 190			
2	Electric			
3	Gas	—	—	—
4				
5	Total (Total of lines 2 thru 4)	—	—	—
6				
7	TOTAL Account 190 (Total of lines 5 thru 6)	—	—	—
8	Classification of TOTAL			
9	Federal Income Tax	—	—	—
10	State Income Tax	—	—	—
11	Local Income Tax	—	—	—

Name of Respondent	This Report is:	Date of Report	Year of Report
	(1) ☒ An Original	(Mo, Da, Yr)	
Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

Accumulated Deferred Income Taxes (Account 190) (Continued)

Changes During Year Amounts Debited to Account 410.2 (e)	Changes During Year Amounts Credited to Account 411.2 (f)	Adjustments Debits Account No. (g)	Adjustments Debits Amount (h)	Adjustments Credits Account No. (i)	Adjustments Credits Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
—	—	—	—	—	—	—	3
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—	—	—	—	—	—	—	5
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—	—	—	—	—	—	—	7
							8
—	—	—	—	—	—	—	9
—	—	—	—	—	—	—	10
—	—	—	—	—	—	—	11

Name of Respondent	This Report is:	Date of Report	Year of Report
	(1) ☒ An Original	(Mo, Da, Yr)	
Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

CAPITAL STOCK (Account 201 and 204)

1. Report below the detail called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock.

2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.

3. Give details concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.

Line No.	Class and Series of Stock and Name of Stock Exchange (a)	Number of Shares Authorized by Charter (b)	Par of Stated Value per Share (c)	Call Price at End of Year (d)
1	Common Stock	100,000,000	N/A	
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CAPITAL STOCK (Accounts 201 and 204) (Continued)

4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or noncumulative.

5. State in a footnote if any capital stock which has been nominally issued is nominally outstanding at end of year.

6. Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purpose of pledge.

Outstanding per Bal. Sheet (total amount outstanding without reduction for amts held by respondent) Shares (e)	Outstanding Per Bal. Sheet Amount (f)	Held by Respondent as Reacquired Stock (Acct 217) Shares (g)	Held by Respondent as Reacquired Stock (Acct 217) Cost (h)	Held by Respondent in Sinking and Other Funds Shares (i)	Held by Respondent in Sinking and Other Funds Amount (j)	Line No.
28,735,705	451,282,098					1
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CAPITAL STOCK SUBSCRIBED, CAPITAL STOCK LIABILITY FOR CONVERSION,PREMIUM ON CAPITAL STOCK, AND INSTALLMENTS RECEIVED ON CAPITAL STOCK(Accounts 202, 203, 205, 206, 207 and 212)

1. Show for each of the above accounts the amounts applying to each class and series of capital stock.

2. For Account 202, Common Stock Subscribed, and Account 205, Preferred Stock Subscribed, show the subscription price and the balance due on each class at the end of year.

3. Describe in a footnote the agreement and transactions under which a conversion liability existed under Account 203, Common Stock Liability for Conversion, or Account 206, Preferred Stock Liability for Conversion, at the end of the year.

4. For Premium on Account 207, Capital Stock, designate with an asterisk any amounts representing the excess of consideration received over stated values of stocks without par value.

Line No.	Name of Account and Description of Item (a)	* (b)	Number of Shares (c)	Amount (d)
1	Account 202 - Common Stock Subscribed			None
2	Account 205 - Preferred Stock Subscribed			None
3	Account 203 and 206 - Capital Stock Liability for Conversion			None
4	Account 207 - Premium on Capital Stock:			None
5	Account 212 - Installments Received on Capital Stock			51,283
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30	**Total**			**51,283**

OTHER PAID IN CAPITAL (Accounts 208 - 211)

1. Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as total of all accounts for reconciliation with balance sheet, page 112. Explain changes made in any account during the year and give the accounting entries effecting such change.

a) Donations Received from Stockholders (Account 208) - State amount and give briefly explain the origin and purpose of each donation.

(b) Reduction in Par or Stated Value of Capital Stock (Account 209) - State amount and give briefly explain the capital changes that gave rise to amounts reported under this caption including identification with the class and series of stock to which related.

(c) Gain on Resale or Cancellation of Reacquired Capital Stock (Account 210) - Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.

(d) Miscellaneous Paid-In Capital (Account 211) - Classify amounts included in this account according to captions that, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	Account 208 - Donations Received from Stockholders	NONE
2	Account 209 - Reduction in Par or Stated Value of Capital Stock	NONE
3	Account 210 - Gain on Resale or Cancellation of Reacquired Capital Stock	
4	Balance At Beginning of Year	1,649,864
5	Credit:	—
6	Debit:	—
7	Balance at End of Year	1,649,864
8	Account 211 - Miscellaneous Paid-In Capital	NONE
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30	**Total**	**1,649,864**

Name of Respondent	This Report is:	Date of Report	Year of Report
	(1) ☒ An Original	(Mo, Da, Yr)	
Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

DISCOUNT ON CAPITAL STOCK (ACCOUNT 213)

1. Report the balance at end of year of discount on capital stock for each class and series of capital stock. Use as many rows as necessary to report all data.

2. If any change occurred during the year in the balance with respect to any class or series of stock, attach a statement giving details of the change. State the reason for any charge-off during the year and specify the account charged.

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1	N/A	—
2		
3		
4		
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14		
	TOTAL	

CAPITAL STOCK EXPENSE (ACCOUNT 214)

1. Report the balance at end of year of capital stock expenses for each class and series of capital stock. Use as many rows as necessary to report all data. Number the rows in sequence starting from the last row number used for Discount on Capital Stock above.

2. If any change occurred during the year in the balance with respect to any class or series of stock, attach a statement giving details of the change. State the reason for any charge-off of capital stock expense and specify the account charged.

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
15	Capital Stock Expense	4,118,163
16		
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24		
25		
26		
27		
	TOTAL	**4,118,163**

Name of Respondent	This Report is:	Date of Report	Year of Report
	(1) ☒ An Original	(Mo, Da, Yr)	
Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

SECURITIES ISSUED OR ASSUMED AND SECURITIES REFUNDED OR RETIRED DURING THE YEAR

1. Furnish a supplemental statement briefly describing security financing and refinancing transactions during the year and the accounting for the securities, discounts, premiums, expenses, and related gains or losses.

2. Provide details showing the full accounting for the total principal amounts, par value, or stated value of each class and series of security issued, assumed, retired, or refunded and the accounting for premiums, discounts, expenses, and gains or losses relating to the securities. Set forth the facts of the accounting clearly with regard to redemption premiums, unamortized discounts, expenses, and gain or losses relating to securities retired or refunded, including the accounting for such amounts carried in the respondent's accounts at the date of the refunding or refinancing transactions with respect to securities previously refunded or retired.

3. Include in the identification of each class and series of security, as appropriate, the interest or dividend rate, nominal date of issuance, maturity date, aggregate principal amount, par value or stated value, and number of shares. Give also the issuance of redemption price and name of the principal underwriting firm through which the security transactions were consummated.

4. Where the accounting for amounts relating to securities refunded or retired is other than that specified in General Instruction 17 of the Uniform System of Accounts, cite the Commission authorization for the different accounting and state the accounting method.

5. For securities assumed, give the name of the company for which the liability on the securities was assumed as well as details of the transactions whereby the respondent undertook to pay obligations of another company. If any unamortized discount, premiums, expenses, and gains or losses were taken over onto the respondent's books, furnish details of these amounts with amounts relating to refunded securities clearly earmarked.

Class of Security	Underwriter of Payee	Date	Stated or Par Value per Share	Number of Shares	Principal Amount or Par Value
Debt Securities Issued					
Secured Medium Term Notes[1]		9/13/2017			100,000,000
			Total Debt Issued		100,000,000
Common Stock					
Common Stock issued:					
Stock option plan	Issued by Company	Various	NA	88,275	4,457,060
ESPP	Issued by Company	12/29/2017	NA	17,603	888,423
			Total Common Stock Issued	105,878	5,345,483

1) Issuance is comprised of two notes, see pages 256 - 258, lines 18 and 28, respectively, for additional issuance information.

Name of Respondent	This Report is:	Date of Report	Year of Report
	(1) ☒ An Original	(Mo, Da, Yr)	
Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

LONG-TERM DEBT (Account 221, 222, 223, and 224)

1. Report by Balance Sheet Account the details concerning long-term debt included in Account 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other Long-Term Debt.

2. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.

3. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.

4. For receivers' certificates, show in column (a) the name of the court and date of court order under which such certificates were issued.

Line No.	Class and Series of Obligation and Name of Stock Exchange (a)		Nominal Date of Issue (b)	Date of Maturity (c)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (d)
1	**Account 221**				
2	First Mortgage Bonds				
3					
4	6.600%	Series B	3/17/1998	3/16/2018	22,000,000
5	1.545%	Series B	12/5/2016	12/5/2018	75,000,000
6	8.310%	Series B	9/21/1994	9/21/2019	10,000,000
7	7.630%	Series B	12/9/1999	12/9/2019	20,000,000
8	5.370%	Series B	3/25/2009	2/1/2020	75,000,000
9	9.050%	Series A	8/13/1991	8/13/2021	10,000,000
10	3.176%	Series B	9/12/2011	9/15/2021	50,000,000
11	3.542%	Series B	8/19/2013	8/19/2023	50,000,000
12	5.620%	Series B	11/21/2003	11/21/2023	40,000,000
13	7.720%	Series B	9/6/2000	9/1/2025	20,000,000
14	6.520%	Series B	12/1/1995	12/1/2025	10,000,000
15	7.050%	Series B	10/15/1996	10/15/2026	20,000,000
16	3.211%	Series B	12/5/2016	12/5/2026	35,000,000
17	7.000%	Series B	5/20/1997	5/21/2027	20,000,000
18	2.822%	Series B	9/13/2017	9/13/2027	25,000,000
19	6.650%	Series B	11/10/1997	11/10/2027	19,700,000
20	6.650%	Series B	6/1/1998	6/1/2028	10,000,000
21	7.740%	Series B	8/29/2000	8/29/2030	20,000,000
22	7.850%	Series B	9/6/2000	9/1/2030	10,000,000
23	5.820%	Series B	9/24/2002	9/24/2032	30,000,000
24	5.660%	Series B	2/25/2003	2/25/2033	40,000,000
25	5.250%	Series B	6/21/2005	6/21/2035	10,000,000
26	4.000%	Series B	10/30/2012	10/31/2042	50,000,000
27	4.136%	Series B	12/5/2016	12/5/2046	40,000,000
28	3.685%	Series B	9/13/2017	9/13/2047	75,000,000
29			Total First Mortgage Bonds		786,700,000
30	**Account 239**				
31	Less: Debt due with-in one year				(97,000,000)
32	**Accounts 222 and 223**				
33	None				—
34	**Account 224**				
35	None				—
36					
37					
38					
39					
40	**TOTAL**				**689,700,000**

LONG-TERM DEBT (Accounts 221, 222, 223 and 224) (Continued)

5. In a supplemental statement, give explanatory details for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principal repaid during year. Give Commission authorization numbers and dates.

6. If the respondent has pledged any of its long-term debt securities, give particulars (details) in a footnote, including name of the pledgee and purpose of the pledge.

7. If the respondent has any long-term securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.

8. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (f). Explain in a footnote any difference between the total of column (f) and the total of Account 427, Interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.

9. Give details concerning any long-term debt authorized by a regulatory commission but not yet issued.

Interest for Year Rate in (%) (e)	Interest for Year Amount (f)	Held by Respondent Reacquired Bonds (Acct. 222) (g)	Held by Respondent Sinking and Other Funds (h)	Redemption Price per $100 at End of Year (i)	Line No.
					1
					2
7.000%	1,633,333			N/A	3
6.600%	1,452,000			N/A	4
1.545%	1,158,750			N/A	5
8.310%	831,000			N/A	6
7.630%	1,526,000			N/A	7
5.370%	4,027,500			N/A	8
9.050%	905,000			N/A	9
3.176%	1,588,000			N/A	10
3.542%	1,771,000			N/A	11
5.620%	2,248,000			N/A	12
7.720%	1,544,000			N/A	13
6.520%	652,000			N/A	14
7.050%	1,410,000			N/A	15
3.211%	1,123,850			N/A	16
7.000%	1,400,000			N/A	17
2.822%	211,650			N/A	18
6.650%	1,310,050			N/A	19
6.650%	665,000			N/A	20
7.740%	1,548,000			N/A	21
7.850%	785,000			N/A	22
5.820%	1,746,000			N/A	23
5.660%	2,264,000			N/A	24
5.250%	525,000			N/A	25
4.000%	2,000,000			N/A	26
4.136%	1,654,400			N/A	27
3.685%	829,125			N/A	28
	36,808,658				29
					30
	—				31
					32
	—				33
					34
	—				37
					38
					39
	36,808,658				**40**

Name of Respondent	This Report is:	Date of Report	Year of Report
	(1) ☒ An Original	(Mo, Da, Yr)	
Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

UNAMORTIZED DEBT EXPENSE, PREMIUM AND DISCOUNT ON LONG-TERM DEBT (Accounts 181, 225, 226)

1. Report under separate subheadings for Unamortized Debt Expense, Unamortized Premium on Long-Term Debt and Unamortized Discount on Long-Term Debt, details of expense, premium or discount applicable to each class and series of long-term debt.

2. Show premium amounts by enclosing figures in parentheses.

3. In column (b) show the principal amount of bonds or other long-term debt originally issued.

4. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.

Line No.	Designation of Long-Term Debt (a)	Principal Amount of Debt Issued (b)	Total Expense Premium or Discount (c)	Amortization Period Date From (d)	Amortization Period Date to (e)
1	**Account 181**				
2	First Mortgage Bonds				
3	7.000%	40,000,000	375,600	8/1/1997	8/1/2017
4	6.600%(2)	22,000,000	1,344,884	3/17/1998	3/16/2018
5	1.545%	75,000,000	633,185	12/5/2016	12/5/2018
6	8.310%(1)	10,000,000	1,111,757	9/21/1994	9/21/2019
7	7.630%	20,000,000	195,421	12/9/1999	12/9/2019
8	5.370%(7)	75,000,000	10,862,808	3/25/2009	2/1/2020
9	9.050%	10,000,000	115,333	8/13/1991	8/13/2021
10	3.176%	50,000,000	605,155	9/12/2011	9/15/2021
11	3.542%	50,000,000	638,179	8/19/2013	8/19/2023
12	5.620%(6)	40,000,000	3,325,438	11/21/2003	11/21/2023
13	7.720%(4)	20,000,000	1,286,261	9/6/2000	9/1/2025
14	6.520%	10,000,000	90,146	12/1/1995	12/1/2025
15	7.050%	20,000,000	175,940	10/15/1996	10/15/2026
16	3.211%	35,000,000	506,753	12/5/2016	12/5/2026
17	7.000%	20,000,000	153,906	5/20/1997	12/5/2026
18	2.822%	25,000,000	364,572	9/13/2017	9/13/2027
19	6.650%(8)	19,700,000	162,800	11/10/1997	11/10/2027
20	6.650%	10,000,000	98,300	6/1/1998	6/1/2028
21	7.740%(3)	20,000,000	1,504,914	8/29/2000	8/29/2030
22	7.850%(5)	10,000,000	753,107	9/6/2000	9/1/2030
23	5.820%	30,000,000	390,382	9/24/2002	9/24/2032
24	5.660%	40,000,000	356,663	2/25/2003	2/25/2033
25	5.250%	10,000,000	97,974	6/21/2005	6/21/2035
26	4.000%	50,000,000	535,479	10/30/2012	10/31/2042
27	4.136%	40,000,000	607,712	12/5/2016	12/5/2046
28	3.685%	75,000,000	906,170	9/13/2017	9/13/2047
29	Shelf Registration Expense	—	—	N/A	N/A
30	Line of Credit	—	—	N/A	N/A
31	**Accounts 225 and 226**				
32	None	—	—	N/A	N/A
33	**TOTAL**	826,700,000	826,700,000		

1) Includes premium and unamortized cost on early redemption of 9.8% series bonds ($1,044,111 allocated to the 8.31% series, and $835,723 allcoated to the 8.26% series).

2) Includes $910,800 premium and $222,664 unamortized costs on early redemption of 9.125% series bonds allocated to the 6.60% series.

3) Includes $992,143 premium, $178,966 unamortized costs on early redemption of 9.75% series bonds, and $148,605 unamortized costs on early redemption of 15.375% series bonds allocated to the 7.74% series.

4) Includes $826,786 premium, $149,139 unamortized costs on early redemption of 9.75% series bonds, and $123,837 unamortized costs on early redemption of 15.375% series bonds allocated to the 7.72% series.

5) Includes $496,071 premium, $89,483 unamortized costs on early redemption of 9.75% series bonds, and $74,302 unamortized costs on early redemption of 15.375% series bonds allocated to the 7.85% series.

6) Includes $150,000 premium and $405,971 unamortized costs on early redemption of 7.50% series bonds, $413,600 premium and $1,116,479 unamortized costs on early redemption of 7.52% series bonds and $730,000 premium and $136,800 unamortized costs on early redemption of 7.25% series bonds allocated to 5.62% series.

7) Includes $10,096,000 costs paid on interest rate hedge loss and $298,058 unamortized costs on shelf registration, allocated to 5.37% series.

8) In November 2009 one investor exercised its right under a one-time put option to redeem $0.3 million of the $20 million outstanding. This one-time put option has now expired, and the remaining $19.7 million remaining principal outstanding is expected to be redeemed at maturity in November 2027.

UNAMORTIZED DEBT EXPENSE, PREMIUM AND DISCOUNT ON LONG-TERM DEBT (Accounts 181, 225, 226) (Continued)

5. Furnish in a footnote details regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

6. Identify separately undisposed amounts applicable to issues which were redeemed in prior years.

7. Explain any debits and credits other than amortization debited to Account 428, Amortization of Debt Discount and Expense, or credited to Account 429, Amortization of Premium on Debt - Credit.

Balance at Beginning of Year (f)	Debits during the Year (g)	Credits During the Year (h)	Balance at End of Year (i)	Line No.
				1
				2
7,729	—	7,729	—	3
12,765	—	10,572	2,193	4
608,571	2,576	316,476	294,671	5
7,350	—	2,700	4,650	6
28,487	—	9,768	18,719	7
3,186,022	—	986,652	2,199,370	8
17,600	—	3,840	13,760	9
282,403	—	60,516	221,887	10
423,333	—	63,817	359,516	11
128,816	—	18,624	110,192	12
64,688	—	7,464	57,224	13
26,750	—	3,000	23,750	14
57,457	—	5,868	51,589	15
502,000	1,218	50,635	452,583	16
56,726	—	8,362	48,364	17
—	309,885	11,135	298,750	18
58,760	—	5,424	53,336	19
37,401	—	3,276	34,125	20
83,782	—	6,168	77,614	21
42,476	—	3,108	39,368	22
205,065	—	13,020	192,045	23
192,254	—	11,892	180,362	24
60,112	—	3,264	56,848	25
460,967	—	17,841	443,126	26
604,911	1,390	20,240	586,061	27
—	930,446	9,259	921,187	28
220,754	103,641	252,682	71,713	29
538,657	—	179,551	359,106	30
7,915,836	1,349,156	2,092,883	7,172,109	31

Total above	2,092,883
Less Shelf Registration Expense	(252,682)
Less LOC amortized to interest expense	(179,551)
Amortization Expense per FERC 428	1,660,650

Name of Respondent	This Report is:	Date of Report	Year of Report
	(1) ☒ An Original	(Mo, Da, Yr)	
Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

UNAMORTIZED LOSS AND GAIN ON REACQUIRED DEBT (Accounts 189, 257)

1. Report under separate subheadings for Unamortized Loss and Unamortized Gain on Reacquired Debt, details of gain and loss, including maturity date, on reacquisition applicable to each class and series of long-term debt. If gain or loss resulted from a refunding transaction, include also the maturity date of the new issue.

2. In column (c) show the principal amount of bonds or other long-term debt reacquired.

3. In column (d) show the net gain or net loss realized on each debt reacquisition as computed in accordance with General Instruction 17 of the Uniform System of Accounts.

4. Show loss amounts by enclosing the figures in parentheses.

5. Explain in a footnote any debits and credits other than amortization debited to Account 428.1, Amortization of Loss on Reacquired Debt or credited to Account 429.1, Amortization of Gain on Reacquired Debt-Credit.

Line No.	Designation of Long-Term Debt (a)	Date Reacquired (b)	Principal of Debt Reacquired (c)	Net Gain or Loss (d)	Balance at Beginning of Year (e)	Balance at End of Year (f)
1	**Account 189**					
2	First Mortgage Bonds					
3	9.8%	11/1/1993	24,938,000	(2,170,710)	114,840	73,080
4	9.13%	4/1/1998	18,000,000	(1,133,464)	66,964	10,084
5	9.75%(1)	9/29/2000	50,000,000	(3,079,332)	1,283,100	1,173,120
6	7.52%(2)	7/1/2003	11,000,000	(1,530,079)	522,750	446,250
7	7.50%(3)	7/1/2003	4,000,000	(555,971)	189,994	162,190
8	7.25%	8/18/2003	20,000,000	(866,800)	296,184	252,840
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30	**TOTAL**				**2,473,832**	**2,117,564**

1) Includes $2,732,588 loss on debt reacquired in 2000 and $346,744 unamortized loss allocated from the 15.375% Guaranteed Notes.

2) Includes $489,200 loss on debt reacquired in 2003 and $1,040,879 unamortized loss allocated from the 9.38% Bonds.

3) Includes $177,360 loss on debt reacquired in 2003 and $378,611 unamortized loss allocated from the 9.38% Bonds.

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

1. Report the reconciliation of reported net income for the year with taxable income used in computing federal income tax accruals

2. If the utility is a member of a group that files a consolidated federal tax return, reconcile reported net income with taxable net income as if a separate return were to be filed, indicating, however, intercompany amounts to be eliminated in such a consolidated return.

Line No.	Details (a)	Amount (b)
1	**Net Income For The Year Per (Page 116)**	(54,613,772)
2	**Reconciling Items for the Year**	
3		
4	Taxable Income Not Reported on Books	
5	Contributions In Aid Of Construction	1,619,204
6	Environmental	3,257,976
7	Uniform Inventory Capitalization	231,225
8	**TOTAL**	5,108,405
9	Deductions Recorded On Books Not Deducted for Return	
10	Accrued Vacation	196,275
11	Bond Redemption Loss Amortization	356,268
12	Meals And Entertainment	448,868
13	Employee Stock Purchase Plan	156,668
14	Deferred Compensation	176,423
15	Capitalized Interest	1,947,664
16	Regulatory Revenue & Cost Adjustments	23,699,850
17	Gas Reserves	10,100,000
18	Federal Tax Provision	33,948,362
19	State Tax Provision	6,979,813
20	**TOTAL**	78,010,191
21	Income Recorded on Books Not Included in Return	
22	SEC Regulatory Interest	(1,009,205)
23	Equity Component Of AFUDC Capitalized For Book	(2,593,209)
24	**TOTAL**	(3,602,414)
25	Deductions on Return Not Charged Against Book Income	
26	Depletion	(854,872)
27	Pension - Deferred Directors Fees	(227,556)
28	Bad Debt Reserve	(334,647)
29	Employee Stock Purchase Plan - Dispositions	(67,052)
30	Stock Based Compensation	(1,946,605)
31	Excess Of Tax Over Book Depreciation	(30,968,316)
32	Pension Adjustments	(13,311,149)
33	Prepaid Insurance	(11,249)
34	Property Tax Adjustment - Accrual To Cash	(967,248)
35	Dividends Paid On Allocated Shares Held By An ESOP	(705,794)
36	Removal Costs	(8,854,692)
37	Miscellaneous	(146,310)
38	Other Non-Utility Earnings	114,208,811
39	TOTAL	55,813,321
40	Federal Tax Net Income	80,715,731
41	Show Computation of Tax:	
42	State Tax	(5,392,127)
43	Federal Tax Net Income, less state tax	75,323,604
44	Federal Tax @ 35%	26,363,261
45	Research and Development Credit	(76,733)
46	Fuel Tax Credit	(25,690)
47	AMT Credit	(10,149,755)
48	Prior years' true-ups and misc adjustments	51,813
49	Total Federal Tax Expense	16,162,896

Name of Respondent	This Report is:	Date of Report	Year of Report
	(1) ☒ An Original	(Mo, Da, Yr)	
Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR, DISTRIBUTION OF TAXES CHARGED
(Show utility dept where applicable and acct charged)

1. Give details of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual or estimated amounts of such taxes are known, show the amounts in a footnote and designate whether estimated or actual amounts.

2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes). Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.

3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b) amounts credited to portion of prepaid taxes charged to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.

4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (a)	Balance at Beg. of Year Taxes Accrued (Account 236) (b)	Balance at Beg. of Year Prepaid Taxes (Incl. in Account 165) (c)
1	**FEDERAL:**		
2	Income Tax (2016)	—	—
3	Income Tax (2017)	1,055,146	—
4	Payroll Tax (2017)	—	—
5	Pipeline Safety User Fee (2017)	1,109,385	—
6	**TOTAL FEDERAL**	2,164,531	—
7	**STATE OF OREGON:**	—	—
8	Excise Tax (2016)	1,181,205	—
9	Excise Tax (2017)	—	—
10	Payroll Tax (2017)	174,555	—
11	Property Tax (2016-2017)	—	10,275,542
12	Property Tax (2017-2018)	—	—
13	Regulatory Commission Fee (2017)	—	—
14	Oregon Department of Energy (2017)	—	—
15	**TOTAL OREGON**	1,355,760	10,275,542
16	STATE OF CALIFORNIA:	—	—
17	Income Tax (2016)	(148,127)	—
18	Income Tax (2017)	—	—
19	**TOTAL CALIFORNIA**	(148,127)	—
20	**STATE OF WASHINGTON:**		
21	Excise Tax (2017)	—	—
22	Payroll Tax (2017)	1,022	—
23	Property Tax (2016)	1,648,579	—
24	Property Tax (2017)	—	—
25	Regulatory Commission Fee (2017)	—	—
26	Public Utility Tax (2016)	367,439.00	—
27	Public Utility Tax (2017)	—	—
28	**TOTAL WASHINGTON**	2,017,040	—
29	**COUNTY & MUNICIPAL:**		
30	Income Tax (2016)	641	—
31	Income Tax (2017)	—	—
32	Franchise Fees	6,724,288	—
33	**TOTAL COUNTY & MUNICIPAL**	6,724,929	—
34			
35	TOTAL	12,114,133	10,275,542

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR, DISTRIBUTION OF TAXES CHARGED (Show utility dept where applicable and acct charged) (Continued)

5. If any tax (exclude Federal and State income taxes) covers more than one year, show the required information separately for each tax year, identifying the year in column (a).

6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a footnote. Designate debit adjustments by parentheses.

7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll

8. Show in columns (i) thru (p) how the taxed accounts were distributed. Show both the utility department and number of account charged. For taxes charged to utility plant, show the number of the appropriate balance sheet plant account or subaccount.

9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

10. Items under $250,000 may be grouped.

11. Report in column (q) the applicable effective state income tax rate

Taxes Charged During the Year (d)	Taxes Paid During the Year (e)	Adjustments (f)	Balance at End of Year Taxes Accrued (Account 236) (g)	Balance at End of Year Taxes Prepaid (Account 165) (h)	Line No.
					1
19,723	2,000,000	925,131	—	—	2
19,284,150	8,500,000	(3,825,492)	6,958,658	—	3
7,912,790	7,587,570	—	1,434,605	—	4
223,585	223,585	—	—	—	5
27,440,248	18,311,155	(2,900,361)	8,393,263	—	6
					7
(100,550)	1,040,000	(40,655)	—	—	8
5,913,583	3,200,000	(983,493)	1,730,090	—	9
1,489,350.00	1,491,256	—	172,649.00	—	10
10,275,542	—	—	—	—	11
11,091,781	22,176,634	—	—	11,084,853	12
1,537,804	1,537,804	—	—	—	13
810,501	810,501	—	—	—	14
31,018,011	30,256,195	(1,024,148)	1,902,739	11,084,853	15
					16
(2,466)	—	150,593	—	—	17
144,987	40,800	(175,193)	(71,006)	—	18
142,521	40,800	(24,600)	(71,006)	—	19
					20
192,434	192,434	—	—	—	21
8,584	9,397	—	209	—	22
(288,995)	1,359,584	—	—	—	23
1,490,642	—	—	1,490,642	—	24
120,705	120,705	—	—	—	25
—	367,439	—	—	—	26
2,991,161	2,633,580	—	357,581	—	27
4,514,531	4,683,139	—	1,848,432	—	28
					29
21,883	50,000	27,476	—	—	30
132,698	180,000	(27,476)	(74,778)	—	31
16,078,162	15,957,513	—	6,844,937	—	32
16,232,743	16,187,513	—	6,770,159	—	33
					34
79,348,054	69,478,802	(3,949,109)	18,843,587	11,084,853	35

Adjustments:

Federal Tax Payments to Subsidiaries	(2,900,361)
State Tax Payments to Subsidiaries	(1,033,885)
Interest Expense	(14,863)
Total	(3,949,109)

Name of Respondent	This Report is:	Date of Report	Year of Report
	(1) ☒ An Original	(Mo, Da, Yr)	
Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR, DISTRIBUTION OF TAXES CHARGED (Show utility dept where applicable and acct charged) (Continued)

1. Give details of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual or estimated amounts of such taxes are known, show the amounts in a footnote and designate whether estimated or actual amounts.

2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes). Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.

3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b) amounts credited to portion of prepaid taxes charged to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.

4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Electric (Account 408.1, 409.1) (i)	Gas (Account 408.1, 409.1) (j)	Other Utility Dept. (Account 408.1, 409.1) (k)	Other Income and Deductions (Account 408.2, 409.2) (l)
1				
2	—	26,123	—	(6,400)
3	—	16,136,773	—	3,147,377
4	—	5,291,409	—	—
5	—	223,585	—	—
6	—	21,677,890	—	3,140,977
7	—	—	—	—
8	—	(99,221)	—	(1,329)
9	—	5,263,091	—	650,492
10	—	995,456	—	—
11	—	9,356,240	—	333,033
12	—	10,362,076	—	348,468
13	—	1,537,804	—	—
14	—	810,501	—	—
15	—	28,225,947	—	1,330,664
16	—	—	—	—
17	—	(2,433)	—	(33)
18	—	129,038	—	15,949
19	—	126,605	—	15,916
20				
21	—	74,573	—	—
22	—	5,738	—	—
23	—	(288,995)	—	—
24	—	1,477,663	—	—
25	—	120,705	—	—
26	—	—	—	—
27	—	2,991,161	—	—
28	—	4,380,845	—	—
29				
30	—	(18,646)	—	—
31	—	(13,026)	—	—
32	—	16,078,162	—	—
33	—	16,046,490	—	—
34				
35	—	70,457,777	—	4,487,557

Name of Respondent	This Report is:	Date of Report	Year of Report
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Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR, DISTRIBUTION OF TAXES CHARGED (Show utility dept where applicable and acct charged) (Continued)

5. If any tax (exclude Federal and State income taxes) covers more than one year, show the required information separately for each tax year, identifying the year in column (a).

6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a footnote. Designate debit adjustments by parentheses.

7. Do not include on this page entries with respect to deductions or otherwise pending transmittal of such taxes to the taxing authority.

8. Show in columns (i) thru (p) how the taxed accounts were distributed. Show both the utility department and number of account charged. For taxes charged to utility plant, show the number of the appropriate balance sheet plant account or subaccount.

9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

10. Items under $250,000 may be grouped.

Extraordinary Items (Account 409.3) (m)	Other Utility Opn. Income (Account 408.1, 409.1) (n)	Adjustment to Ret. Earnings (Account 439) (o)	Other (p)	State/Local Income Tax Rate (q)	Line No.
					1
—	—	—	—	—	2
—	—	—	—	—	3
—	—	—	2,621,381	—	4
—	—	—	—	—	5
—	—	—	2,621,381	—	6
—	—	—	—	—	7
—	—	—	—	—	8
—	—	—	—	—	9
—	—	—	493,894	—	10
—	—	—	586,269	—	11
—	—	—	381,237	—	12
—	—	—	—	—	13
—	—	—	—	—	14
—	—	—	1,461,400	—	15
—	—	—	—	—	16
—	—	—	—	—	17
—	—	—	—	—	18
—	—	—	—	—	19
					20
—	—	—	117,861	—	21
—	—	—	2,846	—	22
—	—	—	—	—	23
—	—	—	12,979	—	24
—	—	—	—	—	25
—	—	—	—	—	26
—	—	—	—	—	27
—	—	—	133,686	—	28
					29
—	—	—	40,529	—	30
—	—	—	145,724	—	31
—	—	—	—	—	32
—	—	—	186,253	—	33
					34
—	—	—	4,402,720	—	35

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	(1) ☒ An Original (2) ☐ A Resubmission		December 31, 2017

MISCELLANEOUS CURRENT AND ACCRUED LIABILITIES (Account 242)

1. Describe and report the amount of other current and accrued liabilities at the end of year.
2. Minor items (less than $250,000) may be grouped under appropriate title.

Line No.	Item (a)	Balance at End of Year (b)
1	Environmental Liabilities - Current Portion	19,087,946
2	Public Purpose	3,853,168
3	OLGA Surcharge	1,474,172
4	Workers Compensation Claims - Current Portion	588,062
5	Deferred Revenue - Appliance Center	682,498
6	Western States Pension - Current Portion	329,793
7	Smart Energy	338,740
8	Other items, each less than $250,000	35,896
9		
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29		
30	**Total**	**26,390,275**

Name of Respondent	This Report is:	Date of Report	Year of Report
	(1) ☒ An Original	(Mo, Da, Yr)	
Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

Other Deferred Credits (Account 253)

1. Report below the details called for concerning other deferred credits
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (less than $250,000) may be grouped by classes

Line No.	Description of OTher Deferred Credits (a)	Balance at The Beginning of the Year (b)	Debit Contra Account (c)	Debit Amount (d)	Credits (e)	Balance at End of Year (f)
1	Western States Pension Plan	7,142,848	—	329,793	—	6,813,055
2	HQ Build-To-Suit Construction Cost	—	—	—	509,972	509,972
3						
4						
5						
6						
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27						
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29						
30	**Total**	**7,142,848**		**329,793**	**509,972**	**7,323,027**

Name of Respondent	This Report is:	Date of Report	Year of Report
	(1) ☒ An Original	(Mo, Da, Yr)	
Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283)

1. Report the information called for below concerning respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.

2. For Other (Specify), included deferrals related to other income and deductions.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Changes During Year Amounts Debited to Account 410.1 (c)	Changes During Year Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Gas			
4	Property Related	417,295,853	25,943,378	10,515,875
5	Regulatory Assets	70,325,455	1,805,356	10,038,822
6	Regulatory Liabilities	—	—	—
7	Other	16,785,730	7,265,517	(3,676,967)
8	Total (Total of lines 3 thru 7)	504,407,038	35,014,251	16,877,730
9	Other - Non-Operating	11,344,768		
10	Other Comprehensive Income	(4,492,689)	23,215,316	21,873,052
11	TOTAL Account 283 (Total of lines 8 thru 10)	511,259,117	58,229,567	38,750,782
12	Classification of TOTAL			
13	Federal Income Tax	430,949,680	52,182,775	34,393,329
14	State Income Tax	80,309,437	6,046,792	4,357,453
15	Local Income Tax	—	—	—

Name of Respondent	This Report is:	Date of Report	Year of Report
	(1) ☒ An Original	(Mo, Da, Yr)	
Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283) (Continued)

3. Provide in a footnote a summary of the type and amount of deferred income taxes reported in the beginning-of-year and end-of-year balances for deferred income taxes that the respondent estimates could be included in the development of jurisdictional recourse rates.

Changes During Year Amounts Debited to Account 410.2	Changes During Year Amounts Credited to Account 411.2	Adjustments Debits Account No.	Adjustments Debits Amount	Adjustments Credits Account No.	Adjustments Credits Amount	Balance at End of Year	Line
(e)	(f)	(g)	(h)	(i)	(j)	(k)	No.
							1
							2
							3
		254, 283	144,698,766			288,024,590	4
658,902		186, 283	41,866,106	186	933,909	21,818,694	5
		254	56,470,134			(56,470,134)	6
		254	16,179,933	283	18,806,177	30,354,458	7
658,902	—		259,214,939		19,740,086	283,727,608	8
(3,074,201)	182,373					8,088,194	9
		218	361,424			(3,511,849)	10
(2,415,299)	182,373		259,576,363		19,740,086	288,303,953	11
							12
(2,663,667)	180,976		255,209,711		14,565,499	205,250,271	13
248,368	1,397		4,366,652		5,174,587	83,053,682	14
—	—		—		—	—	15

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the details called for concerning other regulatory liabilities which are created through the ratemaking actions of regulatory agencies (and not includable in other amounts).

2. For regulatory liabilities being amortized, show period of amortization in column (a).

3. Minor items (5% of the Balance at End of Year for Account 254 or amounts less than $250,000, whichever is less) may be grouped by classes.

4. Provide in a footnote, for each line item, the regulatory citation where the respondent was directed to refund the regulatory liability (e.g Commission Order, state commission order, court decision).

Line No.	Description of Other Regulatory Liabilities (a)	Balance at Beginning of Year (b)	Debits (c)	Credits (d)	Balance at End of Year (e)
1	Storage Margin Share - Oregon (OPUC Advice 00-4 and later OPUC Advice 03-6)	11,462,473	15,721,829	15,954,754	11,695,398
2	Storage Margin Share - Washington (UG 298)	1,430,956	1,558,857	1,589,611	1,461,710
3	Deferred Derivative Unrealized Gains(1)	19,807,152	28,160,487	11,315,094	2,961,759
4	Tax Reform	—	—	213,306,164	213,306,164
5	North Mist COH Regulatory Liability	143,293	—	823,696	966,989
6	Other	125,798	131,798	24,000	18,000
7					
8					
9					
10					
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12					
13					
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16					
17					
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26					
27					
28					
29					
30	**Total**	**32,969,672**	**45,572,971**	**243,013,319**	**230,410,020**

Name of Respondent	This Report is:	Date of Report	Year of Report
	(1) ☒ An Original	(Mo, Da, Yr)	
Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

GAS OPERATING REVENUES (Account 400)

1. Report below natural gas operating revenues for each prescribed account total. The amounts must be consistent with the detailed data on succeeding pages.

2. Revenues in columns (b) and (c) include transition costs from upstream pipelines.

3. Other Revenues in columns (f) and (g) include reservation charges received by the pipeline plus usage charges, less revenues reflected in columns (b) through (e). Include in columns (f) and (g) revenues for Accounts 480 - 495.

Line No.	Title of Account (a)	Revenues for Transition Costs and Take-or-Pay Amount for Current Year (b)	Revenues for Transition Costs and Take-or-Pay Amount for Previous Year (c)	Revenues for GRI and ACA Amount for Current Year (d)	Revenues for GRI and ACA Amount for Previous Year (e)
1	480 Residential Sales				
2	481 Commercial and Industrial Sales				
3	482 Other Sales to Public Authorities				
4	483 Sales for Resale				
5	484 Interdepartmental Sales				
6	485 Intracompany Transfers				
7	487 Forfeited Discounts				
8	488 Miscellaneous Service Revenues				
9	489.1 Revenues from Transportation of Gas of Others Through Gathering Facilities				
10	489.2 Revenues from Transportation of Gas of Others Through Transmission Facilities				
11	489.3 Revenues from Transportation of Gas of Others Through Distribution Facilities				
12	489.4 Revenues from Storing Gas of Others				
13	490 Sales of Prod. Ext. from Natural Gas				
14	491 Revenues from Natural Gas Proc. by				
15	492 Incidental Gasoline and Oil Sales				
16	493 Rent from Gas Property				
17	494 Interdepartmental Rents				
18	495 Other Gas Revenues				
19	Subtotal:				
20	496 (Less) Provision for Rate Refunds				
21	TOTAL:				

GAS OPERATING REVENUES (Account 400) (Continued)

4. If increases or decreases from previous year are not derived from previously reported figures, explain any inconsistencies in a footnote.
5. On Page 108, include information on major changes during the year, new service, and important rate increases or decreases.
6. Report the revenue from transportation services that are bundled with storage services as transportation service revenue.

Other Revenues Amount for Current Year (f)	Other Revenues Amount for Previous Year (g)	Total Operating Revenues Amount for Current Year (h)	Total Operating Revenues Amount for Previous Year (i)	Dekatherm of Natural Gas Amount for Current Year (j)	Dekatherm of Natural Gas Amount for Previous Year (k)	Line No.
458,762,939	400,892,165	458,762,939	400,892,165	46,519,830	37,923,854	1
274,611,130	238,071,859	274,611,130	238,071,859	36,592,210	31,415,415	2
—	—	—	—	—	—	3
—	—	—	—	—	—	4
—	—	—	—	—	—	5
—	—	—	—			6
2,205,197	2,000,024	2,205,197	2,000,024			7
1,153,004	1,098,870	1,153,004	1,098,870			8
—	—	—	—	—	—	9
—	—	—	—	—	—	10
20,351,015	19,876,956	20,351,015	19,876,956	40,917,174	39,160,453	11
—	—	—	—	—	—	12
—	—	—	—			13
—	—	—	—			14
—	—	—	—			15
241,126	385,832	241,126	385,832			16
—	—	—	—			17
(5,313,442)	5,261,370	(5,313,442)	5,261,370			18
752,010,969	667,587,076	752,010,969	667,587,076			19
—	—	—				20
752,010,969	667,587,076	752,010,969	667,587,076			21

OTHER GAS REVENUES (ACCOUNT 495)

Report below transactions of $250,000 or more included in Account 495, Other Gas Revenues. Group all transactions below $250,000 in one amount and provide the number of items.

Line No.	Description of Transaction (a)	Amount (b)
1	Unbilled Revenue	(334,267)
2	Interstate Storage Credit	11,545,237
3	Decoupling	8,637,623
4	Decoupling Amortization	(14,595,839)
5	Washington Amortizations	(2,058,393)
6	Oregon Amortizations	(3,889,037)
7	WA Great Program	(472,237)
8	Warm Deferrals	950,831
9	Warm Amortizations	(5,163,687)
10	Other (Misc Gas Revenues - 4 items)	66,327
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30	**Total**	(5,313,442)

Name of Respondent	This Report is:	Date of Report	Year of Report
	(1) ☒ An Original	(Mo, Da, Yr)	
Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

GAS OPERATION AND MAINTENANCE EXPENSES

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. PRODUCTION EXPENSES		
2	A. Manufactured Gas Production		
3	Manufactured Gas Production (Submit Supplemental Statement)	N/A	N/A
4	B. Natural Gas Production		
5	B1. Natural Gas Production and Gathering		
6	Operation		
7	750 Operation Supervision and Engineering	—	—
8	751 Production Maps and Records	—	—
9	752 Gas Wells Expenses	—	—
10	753 Field Lines Expenses	—	—
11	754 Field Compressor Station Expenses	—	—
12	755 Field Compressor Station Fuel and Power	—	—
13	756 Field Measuring and Regulating Station Expenses	—	—
14	757 Purification Expenses	—	—
15	758 Gas Well Royalties	—	—
16	759 Other Expenses	—	—
17	760 Rents	—	—
18	TOTAL Operation (Total of lines 7 thru 17)	—	—
19	Maintenance		
20	761 Maintenance Supervision and Engineering	—	—
21	762 Maintenance of Structures and Improvements	—	—
22	763 Maintenance of Producing Gas Wells	—	—
23	764 Maintenance of Field Lines	—	—
24	765 Maintenance of Field Compressor Station Equipment	—	—
25	766 Maintenance of Field Meas. and Regulating Station Equipment	—	—
26	767 Maintenance of Purification Equipment	—	—
27	768 Maintenance of Drilling and Cleaning Equipment	—	—
28	769 Maintenance of Other Equipment	—	—
29	TOTAL Maintenance (Total of lines 20 thru 28)	—	—
30	TOTAL Natural Gas Production and Gathering (Total of lines 18 and 29)	—	—

GAS OPERATION AND MAINTENANCE EXPENSES (Continued)

Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)	Line No.
B2. Products Extraction			31
Operation			32
770 Operation Supervision and Engineering	—	—	33
771 Operation Labor	—	—	34
772 Gas Shrinkage	—	—	35
773 Fuel	—	—	36
774 Power	—	—	37
775 Materials	—	—	38
776 Operation Supplies and expenses	—	—	39
777 Gas Processed by Others	—	—	40
778 Royalties on Products Extracted	—	—	41
779 Marketing expenses	—	—	42
780 Products Purchased for Resale	—	—	43
781 Variation in Products Inventory	—	—	44
(Less) 782 Extracted Products Used by the Utility-Credit	—	—	45
783 Rents	—	—	46
Total Operation (Total of Lines 33 thru 46)	—	—	47
Maintenance			48
784 Maintenance Supervision and Engineering	—	—	49
785 Maintenance of Structures and Improvements	—	—	50
786 Maintenance of Extraction and Refining Equipment	—	—	51
787 Maintenance of Pipe Lines	—	—	52
788 Maintenance of Extracted Products Storage Equipment	—	—	53
789 Maintenance of Compressor Equipment	—	—	54
790 Maintenance of Gas Measuring and Regulating Equipment	—	—	55
791 Maintenance of Other Equipment	—	—	56
TOTAL Maintenance (Total of lines 49 thru 56)	—	—	57
TOTAL Products Extraction (Total of lines 47 and 57)	—	—	58

Name of Respondent	This Report is:	Date of Report	Year of Report
	(1) ☒ An Original	(Mo, Da, Yr)	
Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

GAS OPERATION AND MAINTENANCE EXPENSES (Continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
59	C. Exploration and Development		
60	Operation		
61	795 Delay Rentals	—	—
62	796 Nonproductive Well Drilling	—	—
63	797 Abandoned Leases	—	—
64	798 Other Exploration	—	—
65	TOTAL Exploration and Development (Total of lines 61 thru 64)	—	—
66	D. Other Gas Supply Expenses		
67	Operation		
68	800 Natural Gas Well Head Purchases	—	—
69	800.1 Natural Gas Well Head Purchases, Intracompany Transfers	—	—
70	801 Natural Gas Field Line Purchases	12,678,362	13,643,305
71	802 Natural Gas Gasoline Plant Outlet Purchases	—	—
72	803 Natural Gas Transmission Line Purchases	—	—
73	804 Natural Gas City Gate Purchases	295,674,576	243,476,981
74	804.1 Liquefied Natural Gas Purchases	—	—
75	805 Other Gas Purchases	—	—
76	805.1 Purchases Gas Cost Adjustments	15,160,198	(12,185,671)
77	TOTAL Purchased Gas (Total of Lines 68 thru 76)	323,513,136	244,934,615
78	806 Exchange Gas	—	—
79	Purchased Gas Expense		
80	807.1 Well Expense-Purchased Gas	—	—
81	807.2 Operation of Purchased Gas Measuring Stations	—	—
82	807.3 Maintenance of Purchased Gas Measuring Stations	—	—
83	807.4 Purchased Gas Calculations Expense	—	—
84	807.5 Other Purchased Gas Expenses	—	—
85	TOTAL Purchased Gas Expense (Total of lines 80 thru 84)	—	—

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	(1) ☒ An Original	(Mo, Da, Yr)	
Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

GAS OPERATION AND MAINTENANCE EXPENSES (Continued)

Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)	Line No.
808.1 Gas Withdrawn from Storage-Debit	19,821,527	23,171,389	86
(Less) 808.2 Gas Delivered to Storage-Credit	(18,093,918)	(7,296,582)	87
809.1 Withdrawals of Liquefied Natural Gas for Processing-Debit	—	—	88
(Less) 809.2 Deliveries of Natural Gas for Processing-Credit	—	—	89
Gas used in Utility Operation-Credit			90
810 Gas Used for Compressor Station Fuel-Credit	—	—	91
811 Gas Used for Products Extraction-Credit	—	—	92
812 Gas Used for Other Utility Operations-Credit	(221,845)	(221,009)	93
TOTAL Gas Used in Utility Operations-Credit (lines 91 thru 93)	(221,845)	(221,009)	94
813 Other Gas Supply Expenses	—	—	95
TOTAL Other Gas Supply Exp. (Total of lines 77, 78, 85, 86-89, 94, 95)	325,018,900	260,588,413	96
TOTAL Production Expenses (Total of lines 3, 30, 58, 65, 96)	325,018,900	260,588,413	97
2. NATURAL GAS STORAGE, TERMINALING AND PROCESSING EXPENSES			98
A. Underground Storage Expenses			99
Operation			100
814 Operation Supervision and Engineering	—	—	101
815 Maps and Records	—	—	102
816 Well Expenses	286,568	312,486	103
817 Lines Expenses	—	—	104
818 Compressor Station Fuel and Power	81,899	52,084	105
819 Compressor Station Fuel and Power	—	—	106
820 Measuring and Regulating Station Expenses	1,948,927	1,808,684	107
821 Purification Expenses	32,269	79,791	108
822 Exploration and Development	—	—	109
823 Gas Losses	—	—	110
824 Other Expenses	—	—	111
825 Storage Well Royalties	—	—	112
826 Rents	—	—	113
TOTAL Operation (Total of lines of 101 thru 113)	2,349,663	2,253,045	114

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	(1) ☒ An Original (2) ☐ A Resubmission		December 31, 2017

GAS OPERATION AND MAINTENANCE EXPENSES (Continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
115	Maintenance		
116	830 Maintenance Supervision and Engineering	—	—
117	831 Maintenance of Structures and Improvements	—	—
118	832 Maintenance of Reservoirs and Wells	284,043	152,055
119	833 Maintenance of Lines	—	—
120	834 Maintenance of Compressor Station Equipment	39,360	—
121	835 Maintenance of Measuring and Regulating Station Equip.	—	—
122	836 Maintenance of Purification Equipment	—	—
123	837 Maintenance of Other Equipment	—	—
124	TOTAL Maintenance (Total of lines 116 thru 123)	323,403	152,055
125	TOTAL Underground Storage Expenses (lines 114 and 124)	2,673,066	2,405,100
126	B. Other Storage Expenses		
127	Operation		
128	840 Operation supervision and Engineering	71,508	103,873
129	841 Operation Labor and Expenses	—	—
130	842 Rents	—	—
131	842.1 Fuel	—	—
132	842.2 Power	—	—
133	842.3 Gas Losses	—	—
134	TOTAL Operation (Total of lines 128 thru 133)	71,508	103,873
135	Maintenance		
136	843.1 Maintenance Supervision and Engineering	—	—
137	843.2 Maintenance of Structures and Improvements	—	—
138	843.3 Maintenance of Gas Holders	—	—
139	843.4 Maintenance of Purification Equipment	—	—
140	843.5 Maintenance of Liquefaction Equipment	—	—
141	843.6 Maintenance of Vaporizing Equipment	—	—
142	843.7 Maintenance of Compressor Equipment	—	—
143	843.8 Maintenance of Measuring and Regulating Equipment	—	—
144	843.9 Maintenance of Other Equipment	—	—
145	TOTAL Maintenance (Total of lines 136 thru 144)	—	—
146	TOTAL Other Storage Expenses (Total of lines 134 and 145)	71,508	103,873

GAS OPERATION AND MAINTENANCE EXPENSES (Continued)

Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)	Line No.
C. Liquefied Natural Gas Terminaling and Processing Expenses			147
Operation			148
844.1 Operation Supervision and Engineering	1,539,525	1,263,504	149
844.2 LNG Processing Terminal Labor and Expenses	—	—	150
844.3 Liquefaction Processing Labor and Expenses	—	—	151
844.4 Liquefaction Transportation Labor and Expenses	—	—	152
844.5 Measuring and Regulating Labor and Expenses	—	—	153
844.6 Compressor Station Labor and Expenses	—	—	154
844.7 Communication system Expenses	—	—	155
844.8 System Control and Load Dispatching	—	—	156
845.1 Fuel	—	—	157
845.2 Power	—	—	158
845.3 Rents	—	—	159
845.4 Demurrage Charges	—	—	160
845.5 Wharfage Receipts-Credit	(90,056)	—	161
845.6 Processing Liquefied of Vaporized Gas by Others	—	—	162
846.1 Gas Losses	—	—	163
846.2 Other Expenses	—	—	164
TOTAL Operation (Total of lines 149 thru 164)	1,449,469	1,263,504	165
Maintenance			166
847.1 Maintenance Supervision and Engineering	—	—	167
847.2 Maintenance of Structures and Improvements	771,788	1,009,378	168
847.3 Maintenance of LNG Processing Terminal Equipment	—	—	169
847.4 Maintenance of LNG Transportation Equipment	—	—	170
847.5 Maintenance of Measuring and Regulating Equipment	—	—	171
847.6 Maintenance of Compressor Station Equipment	—	—	172
847.7 Maintenance of Communication Equipment	—	—	173
847.8 Maintenance of Other Equipment	—	—	174
TOTAL Maintenance (Total of lines 167 thru 174)	771,788	1,009,378	175
TOTAL Liquefied Nat Gas Terminaling and Proc Exp (Total of lines 165 & 175)	2,221,257	2,272,882	176
TOTAL Natural Gas Storage (Total of lines 125, 146, and 176)	4,965,831	4,781,855	177

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	(1) ☒ An Original (2) ☐ A Resubmission		December 31, 2017

GAS OPERATION AND MAINTENANCE EXPENSES (Continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
178	3. TRANSMISSION EXPENSES		
179	Operation		
180	850 Operation Supervision and Engineering	—	—
181	851 System Control and Load Dispatching	—	—
182	852 Communication system Expenses	—	—
183	853 Compressor Station Labor and Expenses	—	—
184	854 Gas for Compressor Station Fuel	—	—
185	855 Other Fuel and Power for Compressor Stations	—	—
186	856 Mains Expenses	1,422,310	1,593,436
187	857 Measuring and Regulating Station Expenses	—	—
188	858 Transmission and Compression of Gas by Others	—	—
189	859 Other Expenses	—	—
190	860 Rents	—	—
191	TOTAL Operations (Total of lines 180 thru 190)	1,422,310	1,593,436
192	Maintenance		
193	861 Maintenance Supervision and Engineering	—	—
194	862 Maintenance of Structures and Improvements	—	—
195	863 Maintenance of Mains	324,822	8,838
196	864 Maintenance of Compressor Station Equipment	—	—
197	865 Maintenance of Measuring and Regulating Station Equipment	—	—
198	866 Maintenance of Communication Equipment	—	—
199	867 Maintenance of Other Equipment	—	—
200	TOTAL Maintenance (Total of lines 193 thru 199)	324,822	8,838
201	TOTAL Transmission Expenses (Total of lines 191 and 200)	1,747,132	1,602,274
202	4. DISTRIBUTION EXPENSES		
203	Operation		
204	870 Operation Supervision and Engineering	2,606,304	2,202,514
205	871 Distribution Load Dispatching	—	—
206	872 Compressor Station Labor and Expenses	—	—
207	873 Compressor Station Fuel and Power	—	—

GAS OPERATION AND MAINTENANCE EXPENSES (Continued)

Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)	Line No.
874 Mains and Services Expenses	7,833,278	7,031,554	208
875 Measuring and Regulating Station Expenses-General	50,561	(3,088)	209
876 Measuring and Regulating Station Expenses-Industrial	—	—	210
877 Measuring and Regulating Station Expenses-City Gas	553,865	575,316	211
878 Meter and House Regulator Expenses	5,382,954	5,083,679	212
879 Customer Installations Expenses	6,399,826	5,921,555	213
880 Other Expenses	1,481,034	1,143,316	214
881 Rents	228,854	212,407	215
TOTAL Operations (Total of lines 204 thru 215)	24,536,676	22,167,253	216
Maintenance			217
885 Maintenance Supervision and Engineering	3,380,701	4,282,248	218
886 Maintenance of Structures and Improvements	—	—	219
887 Maintenance of Mains	2,702,659	2,814,316	220
888 Maintenance of Compressor Station Equipment	—	—	221
889 Maintenance of Measuring & Regulating Station Equipment-General	1,563,970	1,156,141	222
890 Maintenance of Meas. and Reg. Station Equipment-Industrial	—	—	223
891 Maintenance of Meas & Reg Station Equip-City Gate	188,375	169,641	224
892 Maintenance of Services	642,341	753,961	225
893 Maintenance of Meters and House Regulators	2,522,985	2,223,427	226
894 Maintenance of Other Equipment	23,971	21,545	227
TOTAL Maintenance (Total of lines 218 thru 227)	11,025,002	11,421,279	228
TOTAL Distribution Expenses (Total of lines 216 and 228)	35,561,678	33,588,532	229
5. CUSTOMER ACCOUNTS EXPENSES			230
Operation			231
901 Supervision	1,313,468	1,230,942	232
902 Meter Reading Expenses	832,116	757,932	233
903 Customer Records and Collection Expenses	16,157,912	15,319,519	234

Name of Respondent	This Report is:	Date of Report	Year of Report
	(1) ☒ An Original	(Mo, Da, Yr)	
Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

GAS OPERATION AND MAINTENANCE EXPENSES (Continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
235	904 Uncollectible Accounts	864,691	1,246,447
236	905 Miscellaneous Customer Accounts Expenses	—	—
237	TOTAL Customer Accounts Expenses (Total of lines 232-236)	19,168,187	18,554,840
238	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSE		
239	Operation		
240	907 Supervision	1,886	2,347
241	908 Customer Assistance Expense	467,102	288,080
242	909 Informational and Instructional Expenses	1,743,866	1,595,193
243	910 Miscellaneous Customer Service and Informational Expenses	179,063	180,741
244	TOTAL Customer Service & Information Expenses (Total of lines 240 thru 243)	2,391,917	2,066,361
245	7. SALES EXPENSES		
246	Operation		
247	911 Supervision	143,410	131,652
248	912 Demonstration and Selling Expenses	3,485,124	2,888,558
249	913 Advertising Expenses	401,650	359,822
250	916 Miscellaneous Sales Expenses	—	—
251	TOTAL Sales Expenses (Total of lines 247 thru 250)	4,030,184	3,380,032
252	8. ADMINISTRATIVE AND GENERAL EXPENSES		
253	Operation		
254	920 Administrative and General Salaries	27,835,981	24,627,399
255	921 Office Supplies and Expenses	19,806,564	17,931,470
256	(Less) 922 Administrative Expenses Transferred - Credit	(18,841,642)	(17,463,672)
257	923 Outside Services Employed	10,066,928	8,152,582
258	924 Property Insurance	3,195,612	3,057,126
259	925 Injuries and Damages	409,798	369,181
260	926 Employee Pensions and Benefits	30,314,906	29,324,780
261	927 Franchise Requirements	—	—
262	928 Regulatory Commission Expenses	—	—
263	(Less) 929 Duplicate Charges - Credit	—	—
264	930.1 General Advertising Expenses	—	—
265	930.2 Miscellaneous General Expenses	2,631,840	2,889,711
266	931 Rents	4,788,210	4,678,405
267	TOTAL Operation (Total of lines 254 thru 266)	80,208,197	73,566,982
268	Maintenance		
269	935 Maintenance of General Plant	3,557,910	4,105,070
270	TOTAL Administrative and General Expenses (Total of lines 267 and 269)	83,766,107	77,672,052
271	TOTAL Gas O&M Expenses (Total of lines 97,177, 201, 229, 237, 244, 251, and 270)	476,649,936	402,234,359

Gas Used in Utility Operations

1. Report below details of credits during the year to Accounts 810, 811, and 812.

2. If any natural gas was used by the respondent for which a charge was not made to the appropriate operating expense or other account, list separately in column (c) the Dth of gas used, omitting entries in column (d).

Line No.	Purpose for Which Gas was Used (a)	Account Charged (b)	Natural Gas Gas Used Dth (c)	Natural Gas Amount of Credit (in dollars) (d)	Manufactured Gas Gas Used Dth (e)	Manufactured Gas Amount of Credit (in dollars) (f)
1	810 Gas Used for Compressor Station Fuel - Credit		—	—	N/A	N/A
2	811 Gas Used for Products Extraction - Credit		—	—	N/A	N/A
3	Gas Shrinkage and Other Usage in Respondent's Own Processing		—	—	N/A	N/A
4	Gas Shrinkage, etc. for Respondent's Gas Processed by Others		—	—	N/A	N/A
5	812 Gas Used for Other Utility Operations - Credit (Report separately for each principal use. Group minor uses.)		420,036	221,845	N/A	N/A
6	System - All Districts	Variable	134,476	221,845	N/A	N/A
7	LNG Plants	Inventory	110,203	0*	N/A	N/A
8	Underground Storage Compressors	Inventory	175,357	0*	N/A	N/A
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25	**Total**		**420,036**	**221,845**	**N/A**	**N/A**

* Included in the Cost of Inventory

Name of Respondent	This Report is:	Date of Report	Year of Report
	(1) ☒ An Original	(Mo, Da, Yr)	
Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

MISCELLANEOUS GENERAL EXPENSE (Account 930.2)

1. Provide the information requested below on miscellaneous general expenses.

2. For Other Expenses, show the (a) purpose, (b) recipient and (c) amount of such items. List separately amounts of $250,000 or more however, amounts less than $250,000 may be grouped if the number of items so grouped is shown.

Line No.	Description (a)	Amount (in dollars) (b)
1	Industry association dues	41,219
2	Experimental and general research expenses	
	a. Gas Research Institute (GRI) aka Gas Technology Institute (GTI)	585,000
	b. Other	108,900
3	Publishing and distributing information and reports to stockholders, trustee, registrar, and transfer	
	agent fees and expenses, and other expenses of servicing outstanding securities of the respondent	115,602
4	Other expenses	
8	a. Directors retainers and fees	1,677,068
9	b. Annual shareholder meeting expenses	104,051
10	c. Other miscellaneous expenses	—
5		
6		
7		
8		
9		
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11		
12		
13		
14		
15		
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17		
18		
19		
20		
21		
22		
23		
24		
25	**Total**	**2,631,840**

Name of Respondent	This Report is:	Date of Report	Year of Report
	(1) ☒ An Original	(Mo, Da, Yr)	
Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

Depreciation, Depletion and Amortization of Gas Plant (Accts 403, 404.1, 404.2, 404.3, 405) (Except Amortization of Acquisition Adjustments)

1. Report in Section A the amounts of depreciation expense, depletion and amortization for the accounts indicated and classified according to the plant functional groups shown.

2. Report in Section B, column (b) all depreciable or amortizable plant balances to which rates are applied and show a composite total. (If more desirable, report by plant account, subaccount or functional classifications other than those pre-printed in column (a). Indicate in a footnote the manner in which column (b) balances are obtained. If average balances are used, state the method of averaging used. For column (c) report available information for each plant functional classification listed in column (a). If composite depreciation accounting is used, report available information called for in columns (b) and (c) on this basis. Where the unit-of-production method is used to determine depreciation charges, show in a footnote any revisions made to estimated gas reserves.

3. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state in a footnote the amounts and nature of the provisions and the plant items to which related.

See following pages

RESERVE BALANCES AND ACTIVITY BY FUNCTIONAL CLASS
NW NATURAL

Period Beginning: January 2017
Period Ending: December 2017

Functional Class FERC Plant Account		Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Loss/(Gain)	Ending Reserve*
UTILITY									
Intangible Plant									
301	ORGANIZATION	—	—	—	—	—	—	—	—
302	FRANCHISES & CONSENTS	—	—	—	—	—	—	—	—
303.1	COMPUTER SOFTWARE	23,269,448	2,791,161	—	—	—	154	—	26,060,764
303.2	CUSTOMER INFORMATION SYSTEM	32,348,168	—	—	—	—	—	—	32,348,168
303.3	INDUSTRIAL & COMMERCIAL BIL	4,146,951	—	—	—	—	—	—	4,146,951
303.4	CRMS	683,689	(797)	—	—	—	—	—	682,893
303.5	POWERPLANT SOFTWARE	—	—	—	—	—	—	—	—
	Intangible Plant Subtotal*	60,448,256	2,790,365	—	—	—	154	—	63,238,775
Production Plant - Oil Gas									
304.1	LAND	—	—	—	—	—	—	—	—
305.2	P P O G STRU & IMPR-SEWER S	—	—	—	—	—	—	—	—
305.5	P P O G STRU & IMPR-OTHER Y	13,814	—	—	—	—	—	—	13,814
312.3	P P O G FUEL HANDLING AND S	—	—	—	—	—	—	—	—
318.3	P P O G LIGHT OIL REFINING	152,141	—	—	—	—	—	—	152,141
318.5	P P O G TAR PROCESSING	255,729	—	—	—	—	—	—	255,729
325	NATURAL GAS PROD AND GATHER	—	—	—	—	—	—	—	—
327	NATURAL GAS PROD & GATHERIN	—	—	—	—	—	—	—	—
328	NATURAL GAS PROD AND GATHER	—	—	—	—	—	—	—	—
331	NATURAL GAS PROD & GATHERIN	—	—	—	—	—	—	—	—
332	NATURAL GAS PROD & GATHERIN	—	—	—	—	—	—	—	—
333	NATURAL GAS PROD & GATHERIN	—	—	—	—	—	—	—	—
334	NATURAL GAS PROD & GATHERIN	—	—	—	—	—	—	—	—
	Production Plant - Oil Gas Subtotal*	421,683	—	—	—	—	—	—	421,683
Production Plant - Other									
305.11	GAS PRODUCTION - COTTAGE G	8,736	—	—	—	—	—	—	8,736
305.17	STRUCTURES MIXING STATION	51,246	—	—	—	—	—	—	51,246
311	P P OTHER-LIQUEFIED PETROLE	—	—	—	—	—	—	—	—
311.4	P P OTHER-L P G GRANGER	—	—	—	—	—	—	—	—
311.7	LIQUIFIED GAS EQUIPMENT COO	8,066	—	—	—	—	—	—	8,066
311.8	LIQUIFIED GAS EQUIPMENT LIN	6,585	—	—	—	—	—	—	6,585
319	GAS MIXING EQUIPMENT GASCO	194,720	—	—	—	—	—	—	194,720
	Production Plant - Other Subtotal*	269,353	—	—	—	—	—	—	269,353

RESERVE BALANCES AND ACTIVITY BY FUNCTIONAL CLASS

NW NATURAL

Period Beginning: January 2017

Period Ending: December 2017

Functional Class / FERC Plant Account		Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Loss/(Gain)	Ending Reserve*
UTILITY									
Natural Gas Underground Storage									
350.1	LAND	—	—	—	—	—	—	—	—
350.2	RIGHTS-OF-WAY	26,919	1,776	—	—	—	—	—	28,695
351	STRUCTURES AND IMPROVEMENTS	2,665,916	123,910	—	—	—	—	—	2,789,826
352	WELLS	11,390,537	414,974	—	—	—	—	—	11,805,512
352.1	STORAGE LEASEHOLD & RIGHTS	1,593,616	76,801	—	—	—	—	—	1,670,417
352.2	RESERVOIRS	2,384,777	146,178	—	—	—	—	—	2,530,955
352.3	NON-RECOVERABLE NATURAL GAS	3,319,796	121,089	—	—	—	—	—	3,440,885
353	LINES	3,041,105	134,967	—	—	—	—	—	3,176,072
354	COMPRESSOR STATION EQUIPMENT	17,881,027	848,770	—	—	—	—	—	18,729,797
355	MEASURING / REGULATING EQUIPM	4,424,715	158,994	—	—	—	—	—	4,583,709
356	PURIFICATION EQUIPMENT	225,070	7,375	—	—	—	—	—	232,445
357	OTHER EQUIPMENT	827,385	30,370	—	—	—	—	—	857,756
	Natural Gas Underground Storage Subtotal*	47,780,863	2,065,204	—	—	—	—	—	49,846,067
Local Storage Plant									
360.11	LAND - LNG LINNTON	—	—	—	—	—	—	—	—
360.12	LAND - LNG NEWPORT	—	—	—	—	—	—	—	—
360.2	LAND - OTHER	—	—	—	—	—	—	—	—
361.11	STRUCTURES & IMPROVEMENTS	2,189,212	276,314	(25,020)	—	—	—	—	2,440,507
361.12	STRUCTURES & IMPROVEMENTS	2,477,560	393,476	(488,187)	—	—	(104,623)	—	2,278,225
361.2	STRUCTURES & IMPROVEMENTS -	10,959	466	—	—	—	—	—	11,425
362.11	GAS HOLDERS - LNG LINNTON	2,241,345	102,509	—	—	—	—	—	2,343,855
362.12	GAS HOLDERS - LNG NEWPORT	5,578,002	157,571	—	—	—	—	—	5,735,573
362.2	GAS HOLDERS - LNG OTHER	1,193	21	—	—	—	—	—	1,213
363.11	LIQUEFACTION EQUIP. - LINN	2,495,345	93,732	(27,318)	—	—	—	—	2,561,759
363.12	LIQUEFACTION EQUIP - NEWPO	7,119,569	67,826	(76,582)	—	—	39,178	—	7,149,990
363.21	VAPORIZING EQUIP - LINNTON	2,662,282	55,948	(316,443)	—	—	(5,293)	—	2,396,494
363.22	VAPORIZING EQUIP - NEWPORT	2,615,653	3,794	(2,328,558)	—	—	(156)	—	290,733
363.31	COMPRESSOR EQUIP - LINNTON	206,897	—	—	—	—	—	—	206,897
363.32	COMPRESSOR EQUIPMENT - NE	367,637	177,133	—	—	—	8,596	—	553,366
363.41	MEASURING & REGULATING EQU	604,762	526	—	—	—	5,293	—	610,581
363.42	MEASURING & REGULATING EQU	118,309	26,008	(9,934)	—	—	55,772	—	190,155
363.5	CNG REFUELING FACILITIES	1,360,531	31,733	—	—	—	—	—	1,392,264
363.6	LNG REFUELING FACILITIES	739,473	—	—	—	—	—	—	739,473
	Local Storage Plant Subtotal*	30,788,729	1,387,056	(3,272,043)	—	—	(1,232)	—	28,902,511

RESERVE BALANCES AND ACTIVITY BY FUNCTIONAL CLASS

NW NATURAL

Period Beginning: January 2017

Period Ending: December 2017

Functional Class / FERC Plant Account		Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Loss/(Gain)	Ending Reserve*
UTILITY									
Transmission Plant									
365.1	LAND	—	—	—	—	—	—	—	—
365.2	LAND RIGHTS	1,886,332	122,003	—	—	—	—	—	2,008,335
366.3	STRUCTURES & IMPROVEMENTS -	298,976	30,148	—	—	—	—	—	329,124
367	MAINS	27,866,944	4,685,280	—	—	—	—	—	32,552,224
367.21	NORTH MIST TRANSMISSION LI	1,079,882	50,054	—	—	—	—	—	1,129,936
367.22	SOUTH MIST TRANSMISSION LI	10,301,352	367,672	—	—	—	—	—	10,669,024
367.23	SOUTH MIST TRANSMISSION LI	12,757,392	931,147	—	—	—	—	—	13,688,539
367.24	11.7M S MIST TRANS LINE	5,271,948	452,281	—	—	—	—	—	5,724,229
367.25	12M NORTH S MIST TRANS	5,307,360	485,717	—	—	—	—	—	5,793,077
367.26	38M NORTH S MIST TRANS	19,647,514	1,773,685	—	—	—	—	—	21,421,198
368	TRANSMISSION COMPRESSOR	(9)	—	—	—	—	—	—	(9)
369	MEASURING & REGULATE STATION	1,444,979	106,379	—	—	—	—	—	1,551,358
370	COMMUNICATION EQUIPMENT	—	—	—	—	—	—	—	—
	Transmission Plant Subtotal*	85,862,668	9,004,366	—	—	—	—	—	94,867,034
Distribution Plant									
374.1	LAND	—	—	—	—	—	—	—	—
374.2	LAND RIGHTS	1,420,339	141,282	—	—	—	—	—	1,561,621
375	STRUCTURES & IMPROVEMENTS	80,809	6,047	—	—	—	—	—	86,857
376.11	MAINS < 4"	311,528,527	14,565,632	(175,814)	(878,723)	9,405	360	—	325,049,387
376.12	MAINS 4" & >	211,230,558	12,926,901	(217,371)	(864,307)	27,222	417	—	223,103,421
377	COMPRESSOR STATION EQUIPMENT	630,397	19,068	—	—	—	—	—	649,465
378	MEASURING & REG EQUIP - GENER	11,523,264	726,592	—	—	—	—	—	12,249,857
379	MEASURING & REG EQUIP - GATE	2,063,027	391,504	—	—	—	—	—	2,454,531
380	SERVICES	388,319,622	20,342,670	(1,162,235)	(1,248,131)	—	301	—	406,252,227
381	METERS	21,812,403	2,020,749	(696,854)	—	—	(56,230)	—	23,080,068
381.1	METERS (ELECTRONIC)	1,313,599	339,434	—	—	—	—	—	1,653,033
381.2	ERT (ENCODER RECEIVER TRANS	18,712,771	2,737,004	(403,962)	—	—	56,230	—	21,102,043
382	METER INSTALLATIONS	7,264,856	1,423,070	(1,694,704)	—	—	—	—	6,993,222
382.1	METER INSTALLATIONS (ELECTR	52,024	11,490	—	—	—	—	—	63,514
382.2	ERT INSTALLATION (ENCODER	4,922,504	621,461	(74,826)	—	—	—	—	5,469,140
383	HOUSE REGULATORS	216,165	50,367	—	—	—	—	—	266,532
386	OTHER PROPERTY ON CUSTOMERS P	—	—	—	—	—	—	—	—
387.1	CATHODIC PROTECTION TESTING	141,431	956	—	—	—	—	—	142,388
387.2	CALORIMETERS @ GATE STATIONS	96,424	—	—	—	—	—	—	96,424
387.3	METER TESTING EQUIPMENT	72,671	—	—	—	—	—	—	72,671
	Distribution Plant Subtotal*	981,401,393	56,324,229	(4,425,765)	(2,991,160)	36,627	1,078	—	1,030,346,401

RESERVE BALANCES AND ACTIVITY BY FUNCTIONAL CLASS

NW NATURAL

Period Beginning: January 2017

Period Ending: December 2017

Functional Class FERC Plant Account		Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Loss/(Gain)	Ending Reserve*
UTILITY									
General Plant									
389	LAND	437,351	—	—	—	—	—	—	437,351
390	STRUCTURES & IMPROVEMENTS	9,465,894	1,171,021	—	—	—	—	—	10,636,915
390.1	SOURCE CONTROL PLANT	3,268,635	1,000,355	—	—	—	—	—	4,268,990
391.1	OFFICE FURNITURE & EQUIPMEN	7,327,274	882,885	—	—	—	—	—	8,210,159
391.2	COMPUTERS	16,146,225	4,188,715	(4,117,001)	—	—	—	—	16,217,939
391.3	ON SITE BILLING	—	—	—	—	—	—	—	—
391.4	CUSTOMER INFORMATION SYSTEM	—	—	—	—	—	—	—	—
392	TRANSPORTATION EQUIPMENT	9,372,980	2,030,014	(1,737,627)	—	223,715	—	—	9,889,082
393	STORES EQUIPMENT	119,406	—	—	—	—	—	—	119,406
394	TOOLS - SHOP & GARAGE EQUIPUI	3,445,724	755,141	—	—	4,706	—	—	4,205,571
395	LABORATORY EQUIPMENT	68,293	—	—	—	—	—	—	68,293
396	POWER OPERATED EQUIPMENT	2,923,748	195,991	(441,739)	—	129,938	—	—	2,807,938
397	GEN PLANT-COMMUNICATION EQU	33,654	6,545	—	—	—	—	—	40,199
397.1	MOBILE	407,625	3,234	—	—	—	—	—	410,859
397.2	OTHER THAN MOBILE & TELEMET	1,690,854	—	—	—	—	—	—	1,690,854
397.3	TELEMETERING - OTHER	2,994,749	3,299	—	—	—	—	—	2,998,048
397.4	TELEMETERING - MICROWAVE	950,261	25,997	—	—	—	—	—	976,258
397.5	TELEPHONE EQUIPMENT	252,246	79,749	—	—	—	—	—	331,995
398	GEN PLANT-MISCELLANEOUS EQU	—	—	—	—	—	—	—	—
398.1	PRINT SHOP	83,249	—	—	—	—	—	—	83,249
398.2	KITCHEN EQUIPMENT	3,612	525	—	—	—	—	—	4,137
398.3	JANITORIAL EQUIPMENT	14,873	—	—	—	—	—	—	14,873
398.4	INSTALLED IN LEASED BUILDINGS	10,120	—	—	—	—	—	—	10,120
398.5	OTHER MISCELLANEOUS EQUIPMENT	66,739	—	—	—	—	—	—	66,739
	General Plant Subtotal*	59,083,512	10,343,471	(6,296,367)	—	358,359	—	—	63,488,975
	Utility Property Grand Total*	1,266,056,456	81,914,691	(13,994,175)	(2,991,160)	394,986	—	—	1,331,380,797

RESERVE BALANCES AND ACTIVITY BY FUNCTIONAL CLASS

NW NATURAL

Period Beginning: January 2017

Period Ending: December 2017

Functional Class FERC Plant Account		Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Loss/(Gain)	Ending Reserve*
NON UTILITY									
Intangible Plant									
303.1	COMPUTER SOFWARE	45,293	7,041	—	—	—	—	—	52,333
303.2	CUSTOMER INFORMATION SYSTEM	42,228	4,275	—	—	—	—	—	46,503
Non Utility	Intangible Plant Subtotal*	87,520	11,316	—	—	—	—	—	98,837
Natural Gas Underground Storage									
352	WELLS	3,599,205	350,667	—	—	—	—	—	3,949,872
352.1	STORAGE LEASEHOLD & RIGHTS	201	20	—	—	—	—	—	221
352.2	RESERVOIRS	807,038	69,449	—	—	—	—	—	876,487
353	LINES	354,310	33,982	—	—	—	—	—	388,292
354	COMPRESSOR STATION EQUIPMENT	4,081,273	381,685	—	—	—	—	—	4,462,958
355	MEASURING / REGULATING EQUIPM	1,919,365	192,570	—	—	—	—	—	2,111,935
357	OTHER EQUIPMENT	10,156	1,442	—	—	—	—	—	11,598
Non Utility	Natural Gas Underground Storage Subtotal*	10,771,548	1,029,815	—	—	—	—	—	11,801,363
Transmission Plant									
368	TRANSMISSION COMPRESSOR	2,087,175	238,655	—	—	—	—	—	2,325,830
Non Utility	Transmission Plant Subtotal*	2,087,175	238,655	—	—	—	—	—	2,325,830
Distribution Plant									
376.12	MAINS 4" & >	214,477	21,258	—	—	—	—	—	235,735
Non Utility	Distribution Plant Subtotal*	214,477	21,258	—	—	—	—	—	235,735
General Plant									
389	LAND	—	—	—	—	—	—	—	—
390	STRUCTURES & IMPROVEMENTS	30,041	4,280	—	—	—	—	—	34,321
Non Utility	General Plant Subtotal*	30,041	4,280	—	—	—	—	—	34,321
Non Utility Other									
121.1	NON-UTIL PROP-DOCK	1,947,067	—	—	—	—	—	—	1,947,067
121.2	NON-UTIL PROP-LAND	—	—	—	—	—	—	—	—
121.3	NON-UTIL PROP-OIL ST	2,223,571	14,159	—	—	—	—	—	2,237,730
121.7	NON-UTIL PROP-APPL CENTER	34,262	4,294	—	—	—	—	—	38,556
121.8	NON-UTIL PROP-STORAGE	(1)	—	—	—	—	—	—	(1)
Non Utility	Other*	4,204,899	18,453	—	—	—	—	—	4,223,352
	Non Utility Property Grand Total*	17,395,661	1,323,778	—	—	—	—	—	18,719,439

RESERVE BALANCES AND ACTIVITY BY FUNCTIONAL CLASS

NW NATURAL

Period Beginning: January 2017

Period Ending: December 2017

Functional Class FERC Plant Account	Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Loss/(Gain)	Ending Reserve*
TOTAL SUMMARY ALL UTILITY DEPRECIATION RESERVES		**12/31/2017**						
UTILITY								
108010	(42,583,470)							
108011	1,010,037,958							
108012	12,918,116							
108013	(3,099,839)							
108014	(606,910)							
108015	2,936,669							
108100	—							
108102	359,615,455							
108002	(8,386,166)							
108003	63,377							
108004	485,607							
108666	—							
SUBTOTAL*		1,331,380,797						
ADD:								
108001 REMOVAL WORK IN PROCESS		(28,885,855)						
TOTAL UTILITY DEPRECIATION*		1,302,494,942						
TOTAL SUMMARY ALL NON-UTILITY RESERVES DEPRECIATION								
NON UTILITY								
122026	1,034							
122027	4,355,478							
122028	13,671,824							
122029	(531,316)							
122100	—							
122102	1,313,777							
122002	(91,357)							
TOTAL NON UTILITY DEPRECIATION*		18,719,439						

* May not foot due to rounding

Name of Respondent	This Report is:	Date of Report	Year of Report
	(1) ☒ An Original	(Mo, Da, Yr)	
Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

DEPRECIATION, DEPLETION, AND AMORTIZATION OF GAS PLANT (Continued)

4. Add rows as necessary to completely report all data. Number the additional rows in sequence as 2.10, 3.10, 3.02, etc.

Line No.	Functional Classification (a)	Plant Bases (in thousands) (b)	Applied Depreciation or Amortization Rates (percent) (c)
1	Production and Gathering Plant		
2	Offshore	N/A	N/A
3	Onshore	N/A	N/A
4	Underground Gas Storage Plant	136,632	2.26%
5	Transmission Plant		
6	Offshore	N/A	N/A
7	Onshore	N/A	N/A
8	General Plant	N/A	N/A
9			
10			
11			
12			
13			
14			
15			

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	(1) ☒ An Original (2) ☐ A Resubmission		December 31, 2017

PARTICULARS CONCERNING CERTAIN INCOME DEDUCTIONS AND INTEREST CHARGES ACCOUNTS

Report the information specified below, in the order given, for the respective income deduction and interest charges accounts.

(a) Miscellaneous Amortization (Account 425) - Describe the nature of items included in this account, the contra account charged, the total of amortization charges for the year, and the period of amortization.

(b) Miscellaneous Income Deductions - Report the nature, payee, and amount of other income deductions for the year as required by Accounts 426.1, Donations; 426.2,Life Insurance; 426.3, Penalties; 426.4, Expenditures for Certain Civic, Political and Related Activities; and 426.5,Amounts of less than $250,000 may be grouped by classes within the above accounts.

(c) Interest on Debt to Associated Companies (Account 430) -For each associated company that incurred interest on debt during the year, indicate the amount and interest rate respectively for (a) advances on notes, (b) advances on open account, (c) notes payable, (d) accounts payable, and (e) other debt, and total interest. Explain the nature of other debt on which interest was incurred during the year.

(d) Other Interest Expense (Account 431) - Report details including the amount and interest rate for other interest charges incurred during the year.

Line No.	Item (a)	Amount (b)
1	Account 425 Miscellaneous Amortization	—
3	Account 426.1 Donations	1,020,825
4	Account 426.2 Life Insurance - Increase in CSV and Death Benefits	(2,492,693)
5	Account 426.3 Penalties - Oregon Department of Transportation	400
6	Account 426.4 Civic, Political and Related Activities	1,135,662
7	Account 426.5 Other Deductions	58,035
8	Total Account 426	(277,771)
9	Account 430 Interest on Debt to Associated Companies	—
10	Account 431 Other Interest Expense	
11	Deferred Compensation	522,220
12	Line of Credit	498,719
13	Notes Payable	213,570
14	Other	64,565
15	Total Account 431	1,299,074
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REGULATORY COMMISSION EXPENSES (Account 928)

1. Report below details of regulatory commission expenses incurred during the current year (or in previous years, if being amortized) relating to formal cases before a regulatory body, or cases in which such a body was a party.

2. In column (b) and (c), indicate whether the expenses were assessed by a regulatory body or were otherwise incurred by the utility.

Line No.	Description (Furnish name of regulatory commission or body, the docket or case number, and a description of the case.) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expenses to Date (d)	Deferred in Account 182.3 at Beginning of Year (e)
1					
2	**Northwest Natural does not track expenses by formal regulatory cases.**				
3					
4					
5					
6					
7					
8					
9					
10					
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12					
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19					
20					
21					
22					
23					
24					
25	**Total**				

Name of Respondent	This Report is:	Date of Report	Year of Report
	(1) ☒ An Original	(Mo, Da, Yr)	
Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

REGULATORY COMMISSION EXPENSES (Account 928) (Continued)

3. Show in column (k) any expenses incurred in prior years that are being amortized. List in column (a) the period of amortization.
4. Identify separately all annual charge adjustments (ACA)
5. List in column (f), (g), and (h) expenses incurred during year which were charges currently to income, plant, or other accounts.
6. Minor items (less than $250,000) may be grouped.

Expenses Incurred During Year Charged Currently To Department (f)	Expenses Incurred During Year Charged Currently To Account No. (g)	Expenses Incurred During Year Charged Currently To Amount (h)	Expenses Incurred During Year Charged Currently To Deferred to Account 192.3 (i)	Amortized During Year Contra Account (j)	Amortized During Year Amount (k)	Deferred in Account 182.3 at End of Year (l)	Line No.
							1
Northwest Natural does not track expenses by formal regulatory cases.							2
							3
							4
							5
							6
							7
							8
							9
							10
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Employee Pensions and Benefits (Account 926)

1. Report below the items contained in Account 926, Employee Pensions & Benefits

Line No.	Expense (a)	Amount (b)
1	Health Benefits	10,995,389
2	Pensions - defined benefit plans	5,554,987
3	Defined contribution plans	3,543,045
4	Other postemployment benefit plans	1,711,868
5	Pensions - other	2,516,480
6	Workers compensation	1,045,412
7	Benefits dept salaries and wages	2,353,647
8	Stock compensation expenses	1,657,412
9	Other Benefits	936,666
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30	**Total**	**30,314,906**

DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals and Other Accounts, and enter such amounts in the appropriate lines and columns provided. Salaries and wages billed to the Respondent by an affiliated company must be assigned to the particular operating function(s) relating to the expenses.
In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used. When reporting detail of other accounts, enter as many rows as necessary numbered sequentially starting with 75.01, 75.02, etc

Line No.	Classification (a)	Direct Payroll Distribution (b)	Payroll Billed by Affiliated Companies (c)	Allocation of Payroll Charged for Clearing Accounts (d)	Total (e)
1	Electric				
2	Operation				
3	Production	—	—	—	—
4	Transmission	—	—	—	—
5	Distribution	—	—	—	—
6	Customer Accounts	—	—	—	—
7	Customer Service and Informational	—	—	—	—
8	Sales	—	—	—	—
9	Administrative and General	—	—	—	—
10	TOTAL Operation (Total of lines 3 thru 9)	—	—	—	—
11	Maintenance				
12	Production	—	—	—	—
13	Transmission	—	—	—	—
14	Distribution	—	—	—	—
15	Administrative and General	—	—	—	—
16	TOTAL Maint. (Total of lines 12 thru 15)	—	—	—	—
17	Total Operation and Maintenance				
18	Production (Total of lines 3 and 12)	—	—	—	—
19	Transmission (Total of lines 4 and 13)	—	—	—	—
20	Distribution (Total of lines 5 and 14)	—	—	—	—
21	Customer Accounts (Line 6)	—	—	—	—
22	Customer Service and Informational (Line 7)	—	—	—	—
23	Sales (Line 8)	—	—	—	—
24	Administrative and General (Total of lines 9 and 15)	—	—	—	—
25	TOTAL Oper. and Maint. (Total of lines 18 thru 24)	—	—	—	—
26	Gas				
27	Operation				
28	Production - Manufactured Gas	—	—	—	—
29	Production - Nat. Gas (Including Expl. and Dev.)	—	—	—	—
30	Other Gas Supply	—	—	—	—
31	Storage, LNG Terminaling and Processing	2,117,890	—	274,809	2,392,699
32	Transmission	654,790	—	92,336	747,126
33	Distribution	15,742,460	—	2,290,827	18,033,287
34	Customer Accounts	9,321,164	—	1,217,657	10,538,821
35	Customer Service and Informational	1,559,628	—	163,015	1,722,643
36	Sales	1,481,182	—	176,079	1,657,261
37	Administrative and General	22,772,120	—	2,511,817	25,283,937
38	TOTAL Operation (Total of lines 28 thru 37)	53,649,234	—	6,726,540	60,375,774
39	Maintenance				

Name of Respondent	This Report is:	Date of Report	Year of Report
	(1) ☒ An Original	(Mo, Da, Yr)	
Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

DISTRIBUTION OF SALARIES AND WAGES

Classification (a)	Direct Payroll Distribution (b)	Payroll Billed by Affiliated Companies (c)	Allocation of Payroll Charged for Clearing Accounts (d)	Total (e)	Line No.
Production - Manufactured Gas	—	—	—	—	40
Production - Natural Gas	—	—	—	—	41
Other Gas Supply	—	—	—	—	42
Storage, LNG Terminaling and Processing	564,531	7,426	73,157	645,114	43
Transmission	1,771,589	—	212,460	1,984,049	44
Distribution	6,930,167	—	911,144	7,841,311	45
Administrative and General	1,202,302	—	167,497	1,369,799	46
TOTAL Maint. (Total of lines 40 thru 46)	10,468,589	7,426	1,364,258	11,840,273	47
Gas (Continued)					48
Total Operation and Maintenance					49
Production - Manufactured Gas (Lines 28 and 40)	—	—	—	—	50
Production - Nat. Gas (Including Expl. and Dev.) (Lines 29 and 41)	—	—	—	—	51
Other Gas Supply (Lines 30 and 42)	—	—	—	—	52
Storage, LNG Terminaling and Processing (Lines 31 and 43)	2,682,421	7,426	347,966	3,037,813	53
Transmission (Total of lines 32 and 44)	2,426,379	—	304,796	2,731,175	54
Distribution (Total of lines 33 and 45)	22,672,627	—	3,201,971	25,874,598	55
Customer Accounts (Total of line 34)	9,321,164	—	1,217,657	10,538,821	56
Customer Service and Informational (Total of line 35)	1,559,628	—	163,015	1,722,643	57
Sales (Total of line 36)	1,481,182	—	176,079	1,657,261	58
Administrative and General (Total of lines 37 and 46)	23,974,422	—	2,679,314	26,653,736	59
TOTAL Operation and Maintenance (Total of lines 50 thru 59)	64,117,823	7,426	8,090,798	72,216,047	60
Other Utility Departments					61
Operation and Maintenance	—	—	—	—	62
TOTAL All Utility Dept. (Total of lines 25,60, and 62)	64,117,823	7,426	8,090,798	72,216,047	63
Utility Plant					64
Construction (By Utility Departments)					65
Electric Plant	—	—	—	—	66
Gas Plant	33,456,349	89,256	3,974,797	37,520,402	67
Other	—	—	—	—	68
TOTAL Construction (Total of lines 66 thru 68)	33,456,349	89,256	3,974,797	37,520,402	69
Plant Removal (By Utility Departments)					70
Electric Plant	—	—	—	—	71
Gas Plant	—	—	—	—	72
Other	—	—	—	—	73
TOTAL Plant Removal (Total of lines 71 thru 73)	—	—	—	—	74
Other Accounts (Specify):					75
Merchandising	1,256,162	—	—	1,256,162	75.01
Governmental & Public Affairs	319,230	—	438,373	757,603	75.02
Utility Employee Salary & Wages - Charged to NNGFC	464	—	—	464	75.03
Utility Employee Salary & Wages - Charged to Trail West	1,651	—	—	1,651	75.04
Utility Employee Salary & Wages - Charged to Gill Ranch	168,385	—	—	168,385	75.05
Utility Employee Salary & Wages - Charged to Gas Storage	459,305	—	—	459,305	75.06
Utility Employee Salary & Wages - Charged to Interstate Storage	484,957	3,507	—	488,464	75.07
Utility Employee Salary & Wages - Charged to Coos County	—	—	61,049	61,049	75.08
Utility Employee Salary & Wages - Charged to NWN Energy	26,256	—	—	26,256	75.09
TOTAL Other Accounts	2,716,410	3,507	499,422	3,219,339	76
TOTAL SALARIES AND WAGES	100,290,582	100,189	12,565,017	112,955,788	77

Name of Respondent	This Report is:	Date of Report	Year of Report
	(1) ☒ An Original	(Mo, Da, Yr)	
Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

CHARGES FOR OUTSIDE PROFESSIONAL AND OTHER CONSULTATIVE SERVICES

1. Report the information specified below for all charges made during the year included in any account (including plant accounts) for outside consultative and other professional services. These services include rate, management, construction, engineering, research, financial, valuation, legal, accounting, purchasing, advertising, labor relations, and public relations, rendered for the respondent under written or oral arrangement, for which aggregate payments were made during the year to any corporation, partnership, organization of any kind, or individual (other than for services as an employee or for payments made for medical and related

   (a) Name of person or organization rendering services.

   (b) Total charges for the year.

2. Sum under a description "Other" all of the aforementioned services amounting to $250,000 or less.

3. Total under a description "Total", the total of all of the aforementioned services.

4. Charges for outside professional and other consultative services provided schedule.

Line No.	Description (a)	Amount (in Dollars) (b)
1	SNC-LAVALIN CONSTRUCTORS INC	44,705,412
2	LOY CLARK PIPELINE CO	16,389,993
3	ANCHOR QEA LLC	7,086,291
4	K & D SERVICES OF OREGON	3,779,345
5	SEVENSON ENVIRONMENTAL	3,611,780
6	LOCATING INC	3,584,859
7	BROTHERS PIPELINE CORP	2,339,568
8	BAKER HUGHES OILFIELD OPERATIO	2,274,755
9	LINDE ENGINEERING NORTH AMERIC	1,747,781
10	PAUL GRAHAM DRILLING AND SERVI	1,605,820
11	AIMS/PVIC	1,569,898
12	COLORADO STRUCTURES INC	1,558,990
13	HARDER MECHANICAL CONTRACTORS	1,556,322
14	BRIX PAVING	1,386,297
15	IVOXY CONSULTING LLC	1,340,791
16	PRICEWATERHOUSECOOPERS LLP	1,232,524
17	GEOENGINEERS INC	1,218,224
18	COURTNEY & SON INC	1,202,848
19	HALLIBURTON ENERGY SERVICES	1,185,443
20	PEARL LEGAL GROUP PC	1,182,101
21	STOEL RIVES LLP	1,137,741
22	FES INVESTMENTS INC	1,125,470
23	QUALITY INTEGRATED SERVICES IN	1,114,015
24	HDR ENGINEERING INC	984,984
25	BIZTEK PEOPLE INC	959,589
26	EN ENGINEERING LLC	954,991
27	SURVEYS & ANALYSIS INC	903,718
28	RESOURCE CEMENTING LLC	873,389
29	RAIMORE CONSTRUCTION LLC	837,937
30	THE AUTOMATION GROUP INC	822,557
31	HAHN AND ASSOCIATES INC	819,287
32	BORDERS PERRIN & NORRANDER INC	792,915
33	CREATIVE MEDIA DEVELOPMENT INC	765,813
34	PATRIOT ENVIRONMENTAL SERVICES	731,199
35	ACCENTURE LLP	712,900
36	G A W INC	697,876
37	MOODY'S INVESTORS SERVICE INC	693,500
38	SHI INTERNATIONAL CORP	692,023
39	ARMANINO LLP	646,000
40	IRANI ENGINEERING INC	639,698
41	INFINITY DIRECT	545,184
42	CHARTER MECHANICAL	537,636
43	MORGAN LEWIS & BOCKIUS LLP	487,677
44	OREGON WASHINGTON LABORATORIES	482,785
45	SITECORE USA INC	458,515
46	CONNECTIVE DX INC	443,419
47	MACKAY SPOSITO	442,190
48	THE HDD CO INC	440,905

49	SNAIR EXCAVATING INC	436,277
50	NORTH COAST ELECTRIC	425,635
51	LRS ARCHITECTS INC	417,628
52	C-2 UTILITY CONTRACTORS LLC	415,151
53	ROCKWELL AUTOMATION INC	414,114
54	KERR CONTRACTORS INC	409,067
55	BROTHERTON CORP	405,685
56	STANDARD UTILITY CONTRACTORS	404,420
57	CHRISTENSON ELECTRIC INC	376,210
58	KITTERMAN TRUCKING & EXCAVATIN	369,078
59	E C COMPANY	342,195
60	NORTHWEST STAFFING RESOURCES I	339,837
61	JPMORGAN CHASE BANK	319,167
62	SLALOM LLC	317,090
63	WESTLAKE CONSULTANTS INC	312,357
64	KNOTT INC	302,208
65	PCE PACIFIC INC	301,366
66	JRJ CONSTRUCTION LLC	293,913
67	GEO DRILLING FLUIDS INC	284,910
68	BATEMAN SEIDEL MINER	284,865
69	GENERAL UTILITIES CO	275,244
70	THE LIBERTY CONSULTING GROUP I	256,790
71	ONE CALL CONCEPTS INC	252,397
72	NORDISK SYSTEMS INC	251,783
73	Other (Vendors < $250k)	11,033,405
74	TOTAL	140,543,747

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	(1) ☒ An Original (2) ☐ A Resubmission		December 31, 2017

Transactions with Associated (Affiliated) Companies

1. Report below the information called for concerning all goods or services received from or provided to associated (affiliated) companies amounting to more than $250,000.
2. Sum under a description "Other", all of the aforementioned goods and services amounting to $250,000 or less.
3. Total under a description "Total", the total of all of the aforementioned goods and services.
4. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote the basis of the allocation.

Line No.	Description of the Goods or Service (a)	Name of Associated/Affiliated company (b)	Account(s) Charged or Credited (c)	Amounts Charged or Credited (d)
1	Goods or Services Provided by Affiliated Company			
2	Labor - Salaries & Overhead	NW Natural Gas Storage LLC	Various	839,056
3	Labor - Salaries & Overhead	Gill Ranch Storage LLC	Various	450,783
4	Other	Various	Various	117,635
5	TOTAL			1,407,474
6				
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13				
14				
15	Goods or Services Provided for Affiliated Company			
16	Labor - Salaries & Overhead	NW Natural Gas Storage LLC	Various	430,162
17	Other	Various	Various	224,914
18	TOTAL			655,076
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See Affiliated Interest Report filed annually with the OPUC and the WUTC for information regarding affiliate allocations and billings.

Name of Respondent	This Report is:	Date of Report	Year of Report
	(1) ☒ An Original	(Mo, Da, Yr)	
Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

COMPRESSOR STATIONS

1. Report below details concerning compressor stations. Use the following subheading; field compressor stations, products extraction compressor stations, underground compressor stations, transmission compressor stations, distribution compressor stations, and other compressor stations.

2. For column (a), indicate the production areas where such stations are used. Group relatively small field compressor stations by production areas. Show the number of stations grouped. Identify any station held under a title other than full ownership. State in a footnote the name of owner or co-owner, the nature of respondent's title, and percent of ownership if jointly owned.

Line No.	Name of station and location (a)	Number of Units at Station (b)	Certificated Horsepower for Each Station (c)	Plant Cost (d)
1	Underground Storage Compressors:			
2	Miller Station, Mist, Oregon	4	14,500	41,877,661
3	(Fuel used is natural gas)			
4	Field Compressors: NON-UTILITY			
5	Molalla, Oregon	2	2,219	7,723,454
6	Deer Island, Oregon	1	1,680	2,774,898
7	(Fuel used is natural gas)			
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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	(1) ☒ An Original (2) ☐ A Resubmission		December 31, 2017

COMPRESSOR STATIONS (Continued)

Designate any station that was not operated during the past year. State in a footnote whether the book cost of such station has been retired in the books of account, or what disposition of the station and its book cost are contemplated. Designate any compressor units in transmission compressor stations installed and put into operation during the year and show in a footnote each unit's size and date the unit was placed in operation.

3. For Column (e), include the type of fuel or power, if other than natural gas. If two types of fuel or power are used, show separate entries for natural gas and the other fuel or Power.

Expenses (except depreciation and taxes) Fuel (e)	Expenses (except depreciation and taxes) Power (f)	Expenses (except depreciation and taxes) Other (g)	Gas for Compressor Fuel in Dth (h)	Electricity for Compressor Station kWh (i)	Operational Data Total Compressor Hours of Operation during the Year (j)	Operational Data Number of Compressor Operated at Time of Station Peak (k)	Date of Station Peak (l)	Line No.
								1
6,430	N/A	N/A	175,357	N/A	4,220	2	1/4/2017	2
								3
								4
2,243	N/A	N/A	742	N/A	5*	N/A	N/A	5
33	N/A	N/A	12	N/A	1*	N/A	N/A	6
								7
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Note: Fuel used by the compressors is added to the value of the inventory and expensed as a cost of gas when the inventory is withdrawn from storage.

* Deer Island and Molalla Gate were not run for production during the year. Both were used for maintenance purposes only.

Name of Respondent	This Report is:	Date of Report	Year of Report
	(1) ☒ An Original	(Mo, Da, Yr)	
Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

GAS STORAGE PROJECTS

1. Report injections and withdrawals of gas for all storage projects used by respondent.

Line No.	Item (a)	Gas Belonging to Respondent (Dth) (b)	Gas Belonging to Others (Dth) (c)	Total Amount (Dth) (d)
	STORAGE OPERATIONS (in Dth)			
1	Gas Delivered to Storage			
2	January	97,016	—	97,016
3	February	115,669	—	115,669
4	March	1,216,349	—	1,216,349
5	April	411,690	—	411,690
6	May	1,661,618	—	1,661,618
7	June	998,435	—	998,435
8	July	526,340	—	526,340
9	August	651,095	—	651,095
10	September	1,001,100	—	1,001,100
11	October	816,500	—	816,500
12	November	769,832	—	769,832
13	December	3,888	—	3,888
14	TOTAL (Total of Lines 2 Thru 13)	8,269,532	—	8,269,532
15	Gas Withdrawn from Storage			
16	January	3,433,796	—	3,433,796
17	February	609,155	—	609,155
18	March	252,971	—	252,971
19	April	39,291	—	39,291
20	May	25,600	—	25,600
21	June	45,722	—	45,722
22	July	28,067	—	28,067
23	August	24,071	—	24,071
24	September	6,121	—	6,121
25	October	53,333	—	53,333
26	November	91,297	—	91,297
27	December	2,235,878	—	2,235,878
28	TOTAL (Total of lines 16 thru 27)	6,845,302	—	6,845,302

Note: Storage withdrawals shown above include Jackson Prairie activity, net of fuel (gas measure at the city gate.)

GAS STORAGE PROJECTS

1. On line 4, enter the total storage capacity certificated by FERC.

2. Report total amount in Dth or other unit, as applicable on lines 2, 3, 4, 7. If quantity is converted from Mcf to Dth, provide conversion factor in a footnote.

Line No.	Item (a)	Total Amount (Dth) (b)
	STORAGE OPERATIONS	
1	Total of Working Gas End of Year	12,284,446
2	Cushion Gas (Including Native Gas)	8,007,132
3	Total Gas in Reservoir (Total of Line 1 and 2)	20,291,578
4	Certificated Storage Capacity	NA
5	Number of Injection - Withdrawal Wells (Mist only)	22
6	Number of Observation Wells (Mist only)	23
7	Maximum Day's Withdrawal from Storage (All Underground Storage)	365,124
8	Date of Maximum Days' Withdrawal	1/4/2017
9	LNG Terminal Companies	2
10	Number of Tanks	2
11	Capacity of Tanks (in Dth)	1,600,000
12	LNG Volumes	
13	Received at "Ship Rail"	—
14	Transferred to Tanks	664,753
15	Withdrawn from Tanks	406,453
16	"Boil Off" Vaporization Loss	—

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	(1) ☒ An Original (2) ☐ A Resubmission		December 31, 2017

Transmission Lines

1. Report below, by state, the total miles of transmission lines of each transmission system operated by respondent at end of year.

2. Report separately any lines held under a title other than full ownership. Designate such lines with an asterisk, in column (b) and in a footnote state the name of the owner, or co-owner, nature of respondent's title, and percent of ownership if jointly owned.

3. Report separately any line that was not operated during the past year. Enter in a footnote the details and state whether the book cost of such a line, or any portion thereof, has been retired in the books of account, or what disposition of the line and its book costs are contemplated.

4. Report the number of miles of pipe to one decimal point.

Line No.	Designation (Identification) of Line or Group of Lines (a)	* (b)	Total Miles of Pipe (c)
1	State of Oregon		645.0
2	State of Washington		3.4
3	State of Oregon - Kelso - Beaver	*	1.0
4	State of Washington - Kelso - Beaver	*	17.0
5	State of Oregon - Coos County Pipeline	**	76.8
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* Kelso-Beaver is owned 10% by NW Natural dba KB Pipeline Company 11% by US Gypsum Corp., and 79% by Portland General Electric (PGE); PGE is the operator.

** Coos County Pipeline is operated by NW Natural on behalf of Coos County.

AUXILIARY PEAKING FACILITIES

1. Report below auxiliary facilities of the respondent for meeting seasonal peak demands on the respondent's system, such as underground storage projects, liquefied petroleum gas installations, gas liquefaction plants, oil gas sets, etc.

2. For column (c), for underground storage projects, report the delivery capacity on February 1 of the heating season overlapping the year-end for which this report is submitted. For other facilities, report the rated maximum daily delivery capacities.

3. For column (d), include or exclude (as appropriate) the cost of any plant used jointly with another facility on the basis of predominant use, unless the auxiliary peaking facility is a separate plant as contemplated by general instruction 12 of the Uniform System of Accounts.

Line No.	Location of Facility (a)	Type of Facility (b)	Maximum Daily Delivery Capacity of Facility (Dth) (c)	Cost of Facility (in dollars) (d)	Was Facility Operated on Day of Highest Transmission Peak Delivery
1	Portland, OR	LNG	120,000	20,108,696	No
2	Newport, OR	LNG	100,000	45,599,143	Yes
3	Mist, OR	Underground	520,000	136,632,254	Yes
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Name of Respondent	This Report is:	Date of Report	Year of Report
	(1) ☒ An Original	(Mo, Da, Yr)	
Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

GAS ACCOUNT - NATURAL GAS

1. The purpose of this schedule is to account for the quantity of natural gas received and delivered by the respondent.
2. Natural gas means either natural gas unmixed or any mixture of natural and manufactured gas.
3. Enter in column (c) the Dth as reported in the schedules indicated for the items of receipts and deliveries.
4. Indicate in a footnote the quantities of bundled sales and transportation gas and specify the line on which such quantities are listed.
5. If the respondent operates two or more systems which are not interconnected, submit separate pages for this purpose. Use copies of pages 520.
6. Indicate by footnote the quantities of gas not subject to Commission regulation which did not incur FERC regulatory costs by showing (1) the local distribution volumes another jurisdictional pipeline delivered to the local distribution company portion of the reporting pipeline (2) the quantities that the reporting pipeline transported or sold through its local distribution facilities or intrastate facilities and which the reporting pipeline received through gathering facilities or intrastate facilities, but not through any of the interstate portion of the reporting pipeline, and (3) the gathering line quantities that were not destined for interstate market of that were not transported through any interstate portion of the reporting pipeline.
7. Indicate in a footnote the specific gas purchase expense account(s) and related to which the aggregate volumes reported on Line 3 relate.
8. Indicate in a footnote (1) the system supply quantities of gas that are stored by the reporting pipeline, during the reporting year and also reported as sales, transportation and compression volumes by the reporting pipeline during the same reporting year, (2) the system supply quantities of gas that are stored by the reporting pipeline during the reporting year which the reporting pipeline intends to sell or transport in a future reporting year, and (3) contract storage quantities.
9. Indicate the volumes of pipeline production field sales that are included in both the company's total sales figure and the company's total transportation figure. Add additional information as necessary to the footnotes.

Line No.	Item (a)	Ref. Page No. (b)	Total Amount of Dth (c)
1	NAME OF SYSTEM:		
2	GAS RECEIVED		
3	Gas Purchases (Accounts 800-805)		85,587,673
4	Gas of Others Received for Gathering (Account 489.1)	303	N/A
5	Gas of Others Received for Transmission (Account 489.2)	305	N/A
6	Gas of Others Received for Distribution (Account 489.3) Transportation	301	40,917,174
7	Gas of Others Received for Contract Storage (Account 489.4)	307	N/A
8	Gas of Other Received for Production/Extraction/Processing (Account 490 and 491)		N/A
9	Exchanged Gas Received from Others (Account 806)	328	N/A
10	Gas Received as Imbalances (Account 806)	328	N/A
11	Receipts of Respondent's Gas Transported by Others (Account 858)	332	N/A
12	Other Gas Withdrawn from Storage (Explain) Underground and LNG Storage	512	6,845,302
13	Gas Received from Shippers as Compressor Station Fuel		—
14	Gas Received from Shippers as Lost and Unaccounted for		—
15	Other Receipts (Specify) LPG		—
16	Total Receipts (Total of lines 3 thru 14)		133,350,149
17	GAS DELIVERED		
18	Gas Sales (Accounts 480-495)		83,112,040
19	Deliveries of Gas Gathered for Others (Account 489.1)	303	—
20	Deliveries of Gas Transported for Others (Account 489.2)	305	N/A
21	Deliveries of Gas Distributed for Others (Account 489.3) Transportation	301	40,917,174
22	Deliveries of Contract Storage Gas (Account 489.4)	307	N/A
23	Gas of Other Delivered for Production/Extraction/Processing (Account 490 and 491)		N/A
24	Exchange Gas Delivered to Others (Account 806)	328	N/A
25	Gas Delivered as Imbalances (Account 806)	328	N/A
26	Deliveries of Gas to Others for Transportation (Account 858)	332	N/A
27	Other Gas Delivered to Storage (Explain) Underground and LNG Storage	512	8,269,532
28	Gas Used for Compressor Station Fuel	331	175,357
29	Other Deliveries (Specify) Co Use	331	244,679
30	Total Deliveries (Total of lines 17 thru 27)		132,718,782
31	GAS LOSSES AND GAS UNACCOUNTED FOR		
32	Gas Losses and Gas Unaccounted For		631,367
33	TOTALS		
34	Total Deliveries, Gas Losses & Unaccounted for (Total of lines 30 and 32)		133,350,149

NORTHWEST NATURAL GAS COMPANY

Oregon Supplement to FERC Form 2

December 31, 2017

ANNUAL REPORT

OREGON SUPPLEMENT TO FERC FORM 2

for

MULTI-STATE GAS COMPANIES

INDEX

Name of Respondent	This Report is:	Date of Report	Year of Report
	(1) ☒ An Original	(Mo, Da, Yr)	
Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

STATE OF OREGON - STATEMENT OF INCOME FOR THE YEAR

Line No.	Account (a)	(REF.) PAGE NO. (b)	GAS UTILITY Current Year (c)	GAS UTILITY Previous Year (d)
1	**UTILITY OPERATING INCOME**			
2	Operating Revenues (400)	2		
3	Operating Expenses			
4	Operation Expenses (401)	4-9		
5	Maintenance Expenses (402)	4-9		
6	Depreciation Expense (403)	10		
7	Amort. & Depl. of Utility Plant (404-405)	10		
8	Amort. of Utility Plant Acq. Adj. (406)	10		
9	Amort of Property Losses, Unrecovered Plant and Regulatory Study Costs (407)			
10	Amort. of Conversion Expenses (407)			
11	Taxes Other Than Income Taxes (408.1)	11		
12	Income Taxes - Federal (409.1)	12		
13	Income Taxes - Other (409.1)	13		
14	Provision for Deferred Income Taxes (410.1)	14-21		
15	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	14-21		
16	Investment Tax Credit Adj. - Net (411.4)	22		
17	(Less) Gains from Disp. of Utility Plant (411.6)			
18	Losses from Disp. of Utility Plant (411.7)			
19	TOTAL Utility Operating Expenses (Total of lines 4 thru 18)			
20	Net Utility Operating income (Enter Total of line 2 less 19)			

SEE FERC ANNUAL REPORT PAGES 114-116

STATE OF OREGON - GAS OPERATING REVENUES (Account 400)

Line No.	Account (a)	OPERATING REVENUES Current Year (b)	OPERATING REVENUES Previous Year (c)	Dth of NATURAL GAS SOLD Current Year (d)	Dth of NATURAL GAS SOLD Previous Year (e)	AVG. NO. OF NAT. GAS CUSTOMERS PER MO. Current Year (f)	AVG. NO. OF NAT. GAS CUSTOMERS PER MO. Previous Year (g)
1	GAS SERVICE REVENUES						
2	480 Residential Sales	407,614,445	360,693,758	41,086,200	33,534,071	588,986	579,760
3	481 Commercial and Industrial Sales						
4	Small or Commercial	209,945,511	182,023,481	25,197,832	21,088,654	60,682	60,016
5	Large or Industrial	42,224,400	38,002,903	8,619,074	8,007,153	1,085	1,078
6	482 Other Sales to Public Authorities	—	—	—	—	—	—
7	484 Interdepartmental Sales	—	—	—	—	—	—
8	TOTAL Sales to Ultimate Consumers	659,784,356	580,720,142	74,903,106	62,629,878	650,753	640,854
9	483 Sales for Resale	—	—	—	—	—	—
10	TOTAL Nat. Gas Service Revenues	659,784,356	580,720,142	74,903,106	62,629,878	650,753	640,854
11	Revenues from Manufactured Gas	—	—				
12	TOTAL Gas Service Revenues	659,784,356	580,720,142				
13	OTHER OPERATING REVENUES						
14	485 Intercompany Transfers	—	—				
15	487 Late Payment Charge	2,103,742	1,919,134				
16	488 Misc. Service Revenues	1,021,924	992,793				
17	489 Rev. From Trans. of Gas of Others	17,987,262	17,663,610				
18	490 Sales of Prod. Ext. from Natural Gas	—	—				
19	491 Rev. from Nat. Gas Proc. by Others	—	—				
20	492 Incidental Gasoline and Oil Sales	—	—				
21	493 Rent from Gas Property	225,739	358,376				
22	494 Interdepartmental Rents	—	—				
23	495 Other Gas Revenues	(2,752,049)	5,555,520				
24	TOTAL Other Operating Revenues	18,586,618	26,489,433				
25	TOTAL Gas Operating Revenues	678,370,974	607,209,575				
26	(Less) 496 Provision for Rate Refunds	—	—				
27	TOTAL Gas Operating Revenues Net of Provision for refund	678,370,974	607,209,575				
28	Dist. Type Sales by State (Incl. Main Line Sales to Resid. and Comm. Custrs.)	617,559,956	542,717,239	—			
29	Main Line Industrial Sales (Incl. Main Line Sales to Pub. Authorities)	42,224,400	38,002,903	—			
30	Sales for Resale	—	—	—			
31	Other Sales to Pub. Auth. (Local Dist. Only)	—	—	—			
32	Interdepartmental Sales	—	—	—			
33	TOTAL (Same as Line 10, Columns (b) and (d))	659,784,356	580,720,142	74,903,106			

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STATE OF OREGON - INTERDEPARTMENTAL SALES - NATURAL GAS (Account 484)

Report particulars concerning sales of natural gas included in Account 484

LINE NO.	DEPARTMENT AND BASIS OF CHARGES (a)	POINT OF DELIVERY (b)	MCF (14.73 psia at 60° F) (c)	REVENUE (d)
	NOT APPLICABLE			

RENT FROM GAS PROPERTY AND INTERDEPARTMENTAL RENTS (Accounts 493, 494)

1. Report particulars concerning rents received, included in Accounts 493 and 494.
2. Minor rents may be entered at the total amount for each class of such rents.
3. If rents are included which were arrived at under an arrangement for apportioning expenses of a joint facility, whereby the amount included in this account represents profit or return on property, depreciation, and taxes, give particulars and the basis of apportionment of such charges to Account 493 or 494.
4. Provide a subheading and total for each account.

LINE NO.	NAME OF LESSEE OR DEPARTMENT (Designate associated companies) (a)	DESCRIPTION OF PROPERTY (b)	AMOUNT OF REVENUE FOR YEAR	
			NATURAL GAS PROPERTY (c)	MANUFACTURED GAS PROPERTY (d)
	ACCOUNT 493 - RENT FROM GAS PROPERTY			
1	Koppers Co. Inc.	Facilities, equip., gasco plant		57,550
2	Other	Communication and other	168,189	

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Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

STATE OF OREGON ALLOCATED - GAS OPERATION AND MAINTENANCE EXPENSES

If the amount for previous year is not derived from previously reported figures, explain in footnotes.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. PRODUCTION EXPENSES		
2	A. Manufactured Gas Production		
3	Manufactured Gas Production (Detail Page 4A)	—	—
4	B. Natural Gas Production		
5	B1. Natural Gas Production and Gathering		
6	Operation		
7	750 Operation Supervision and Engineering	—	—
8	751 Production Maps and Records	—	—
9	752 Gas Wells Expenses	—	—
10	753 Field Lines Expenses	—	—
11	754 Field Compressor Station Expenses	—	—
12	755 Field Compressor Station Fuel and Power	—	—
13	756 Field Measuring and Regulating Station Expenses	—	—
14	757 Purification Expenses	—	—
15	758 Gas Well Royalties	**SEE FERC ANNUAL REPORT PAGES 317-325**	
16	759 Other Expenses	—	—
17	760 Rents	—	—
18	TOTAL Operation (Total of lines 7 thru 17)	—	—
19	Maintenance		
20	761 Maintenance Supervision and Engineering	—	—
21	762 Maintenance of Structures and Improvements	—	—
22	763 Maintenance of Producing Gas Wells	—	—
23	764 Maintenance of Field Lines	—	—
24	765 Maintenance of Field Compressor Station Equipment	—	—
25	766 Maintenance of Field Meas. and Regulating Station Equipment	—	—
26	767 Maintenance of Purification Equipment	—	—
27	768 Maintenance of Drilling and Cleaning Equipment	—	—
28	769 Maintenance of Other Equipment	—	—
29	TOTAL Maintenance (Total of lines 20 thru 28)	—	—
30	TOTAL Natural Gas Production and Gathering (Total of lines 18 and 29)	—	—
31	B2. Products Extraction		
32	Operation		
33	770 Operation Supervision and Engineering	—	—
34	771 Operation Labor	—	—
35	772 Gas Shrinkage	—	—
36	773 Fuel	—	—
37	774 Power	—	—
38	775 Materials	—	—
39	776 Operation Supplies and expenses	—	—
40	777 Gas Processed by Others	—	—
41	778 Royalties on Products Extracted	—	—
42	779 Marketing expenses	—	—
43	780 Products Purchased for Resale	—	—
44	781 Variation in Products Inventory	—	—
45	(Less) 782 Extracted Products Used by the Utility-Credit	—	—
46	783 Rents	—	—
47	Total Operation (Total of Lines 33 thru 46)	—	—

Name of Respondent	This Report is:	Date of Report	Year of Report
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Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

STATE OF OREGON ALLOCATED - GAS OPERATION AND MAINTENANCE EXPENSES

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	A. Manufactured Gas Production Detail		
	SEE FERC ANNUAL REPORT PAGES 317-325		

STATE OF OREGON ALLOCATED - GAS OPERATION AND MAINTENANCE EXPENSES (Con't)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
48	Maintenance		
49	784 Maintenance Supervision and Engineering	—	—
50	785 Maintenance of Structures and Improvements	—	—
51	786 Maintenance of Extraction and Refining Equipment	—	—
52	787 Maintenance of Pipe Lines	—	—
53	788 Maintenance of Extracted Products Storage Equipment	—	—
54	789 Maintenance of Compressor Equipment	**SEE FERC ANNUAL REPORT PAGES 317-325**	
55	790 Maintenance of Gas Measuring and Regulating Equipment	—	—
56	791 Maintenance of Other Equipment	—	—
57	TOTAL Maintenance (Total of lines 49 thru 56)	—	—
58	TOTAL Products Extraction (Total of lines 47 and 57)	—	—
59	C. Exploration and Development		
60	Operation		
61	795 Delay Rentals	—	—
62	796 Nonproductive Well Drilling	—	—
63	797 Abandoned Leases	—	—
64	798 Other Exploration	—	—
65	TOTAL Exploration and Development (Total of lines 61 thru 64)	—	—
66	D. Other Gas Supply Expenses		
67	Operation		
68	800 Natural Gas Well Head Purchases	—	—
69	800.1 Natural Gas Well Head Purchases, Intracompany Transfers	—	—
70	801 Natural Gas Field Line Purchases	—	—
71	802 Natural Gas Gasoline Plant Outlet Purchases	—	—
72	803 Natural Gas Transmission Line Purchases	—	—
73	804 Natural Gas City Gate Purchases	—	—
74	804.1 Liquefied Natural Gas Purchases	—	—
75	805 Other Gas Purchases	—	—
76	(Less) 805.1 Purchases Gas Cost Adjustments	—	—
77	TOTAL Purchased Gas (Total of Lines 68 thru 76)	—	—
78	806 Exchange Gas	—	—
79	Purchased Gas Expense		
80	807.1 Well Expense-Purchased Gas	—	—
81	807.2 Operation of Purchased Gas Measuring Stations	—	—
82	807.3 Maintenance of Purchased Gas Measuring Stations	—	—
83	807.4 Purchased Gas Calculations Expense	—	—
84	807.5 Other Purchased Gas Expenses	—	—
85	TOTAL Purchased Gas Expense (Total of lines 80 thru 84)	—	—
86	808.1 Gas Withdrawn from Storage-Debit	—	—
87	(Less) 808.2 Gas Delivered to Storage-Credit	—	—
88	809.1 Withdrawals of Liquefied Natural Gas for Processing-Debit	—	—
89	(Less) 809.2 Deliveries of Natural Gas for Processing-Credit	—	—
90	Gas used in Utility Operation-Credit		
91	810 Gas Used for Compressor Station Fuel-Credit	—	—
92	811 Gas Used for Products Extraction-Credit	—	—
93	812 Gas Used for Other Utility Operations-Credit	—	—
94	TOTAL Gas Used in Utility Operations-Credit (lines 91 thru 93)	—	—
95	813 Other Gas Supply Expenses	—	—
96	TOTAL Other Gas Supply Exp. (Total of lines 77, 78, 85, 86-89, 94, 95)	—	—
97	TOTAL Production Expenses (Total of lines 3, 30, 58, 65, 96)	—	—

Name of Respondent	This Report is:	Date of Report	Year of Report
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Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

STATE OF OREGON ALLOCATED - GAS OPERATION AND MAINTENANCE EXPENSES (Con't)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
98	2. NATURAL GAS STORAGE, TERMINALING AND PROCESSING EXPENSES		
99	A. Underground Storage Expenses		
100	Operation		
101	814 Operation Supervision and Engineering	—	—
102	815 Maps and Records	—	—
103	816 Well Expenses	—	—
104	817 Lines Expenses	—	—
105	818 Compressor Station Fuel and Power	**SEE FERC ANNUAL REPORT PAGES 317-325**	
106	819 Compressor Station Fuel and Power	—	—
107	820 Measuring and Regulating Station Expenses	—	—
108	821 Purification Expenses	—	—
109	822 Exploration and Development	—	—
110	823 Gas Losses	—	—
111	824 Other Expenses	—	—
112	825 Storage Well Royalties	—	—
113	826 Rents	—	—
114	TOTAL Operation (Total of lines of 101 thru 113)	—	—
115	Maintenance		
116	830 Maintenance Supervision and Engineering	—	—
117	831 Maintenance of Structures and Improvements	—	—
118	832 Maintenance of Reservoirs and Wells	—	—
119	833 Maintenance of Lines	—	—
120	834 Maintenance of Compressor Station Equipment	—	—
121	835 Maintenance of Measuring and Regulating Station Equip.	—	—
122	836 Maintenance of Purification Equipment	—	—
123	837 Maintenance of Other Equipment	—	—
124	TOTAL Maintenance (Total of lines 116 thru 123)	—	—
125	TOTAL Underground Storage Expenses (lines 114 and 124)	—	—
126	B. Other Storage Expenses		
127	Operation		
128	840 Operation supervision and Engineering	—	—
129	841 Operation Labor and Expenses	—	—
130	842 Rents	—	—
131	842.1 Fuel	—	—
132	842.2 Power	—	—
133	842.3 Gas Losses	—	—
134	TOTAL Operation (Total of lines 128 thru 133)	—	—
135	Maintenance		
136	843.1 Maintenance Supervision and Engineering	—	—
137	843.2 Maintenance of Structures and Improvements	—	—
138	843.3 Maintenance of Gas Holders	—	—
139	843.4 Maintenance of Purification Equipment	—	—
140	843.5 Maintenance of Liquefaction Equipment	—	—
141	843.6 Maintenance of Vaporizing Equipment	—	—
142	843.7 Maintenance of Compressor Equipment	—	—
143	843.8 Maintenance of Measuring and Regulating Equipment	—	—
144	843.9 Maintenance of Other Equipment	—	—
145	TOTAL Maintenance (Total of lines 136 thru 144)	—	—
146	TOTAL Other Storage Expenses (Total of lines 134 and 145)	—	—

STATE OF OREGON ALLOCATED - GAS OPERATION AND MAINTENANCE EXPENSES (Con't)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
147	C. Liquefied Natural Gas Terminaling and Processing Expenses		
148	Operation		
149	844.1 Operation Supervision and Engineering	—	—
150	844.2 LNG Processing Terminal Labor and Expenses	—	—
151	844.3 Liquefaction Processing Labor and Expenses	—	—
152	844.4 Liquefaction Transportation Labor and Expenses	—	—
153	844.5 Measuring and Regulating Labor and Expenses	**SEE FERC ANNUAL REPORT PAGES 317-325**	
154	844.6 Compressor Station Labor and Expenses	—	—
155	844.7 Communication system Expenses	—	—
156	844.8 System Control and Load Dispatching	—	—
157	845.1 Fuel	—	—
158	845.2 Power	—	—
159	845.3 Rents	—	—
160	845.4 Demurrage Charges	—	—
161	(Less) 845.5 Wharfage Receipts-Credit	—	—
162	845.6 Processing Liquefied of Vaporized Gas by Others	—	—
163	846.1 Gas Losses	—	—
164	846.2 Other Expenses	—	—
165	TOTAL Operation (Total of lines 149 thru 164)	—	—
166	Maintenance		
167	847.1 Maintenance Supervision and Engineering	—	—
168	847.2 Maintenance of Structures and Improvements	—	—
169	847.3 Maintenance of LNG Processing Terminal Equipment	—	—
170	847.4 Maintenance of LNG Transportation Equipment	—	—
171	847.5 Maintenance of Measuring and Regulating Equipment	—	—
172	847.6 Maintenance of Compressor Station Equipment	—	—
173	847.7 Maintenance of Communication Equipment	—	—
174	847.8 Maintenance of Other Equipment	—	—
175	TOTAL Maintenance (Total of lines 167 thru 174)	—	—
176	TOTAL Liquefied Nat Gas Terminaling and Proc Exp (Total of lines 165 & 175)	—	—
177	TOTAL Natural Gas Storage (Total of lines 125, 146, and 176)	—	—
178	3. TRANSMISSION EXPENSES		
179	Operation		
180	850 Operation Supervision and Engineering	—	—
181	851 System Control and Load Dispatching	—	—
182	852 Communication system Expenses	—	—
183	853 Compressor Station Labor and Expenses	—	—
184	854 Gas for Compressor Station Fuel	—	—
185	855 Other Fuel and Power for Compressor Stations	—	—
186	856 Mains Expenses	—	—
187	857 Measuring and Regulating Station Expenses	—	—
188	858 Transmission and Compression of Gas by Others	—	—
189	859 Other Expenses	—	—
190	860 Rents	—	—
191	TOTAL Operations (Total of lines 180 thru 190)	—	—

Name of Respondent	This Report is:	Date of Report	Year of Report
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STATE OF OREGON ALLOCATED - GAS OPERATION AND MAINTENANCE EXPENSES (Con't)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
192	Maintenance		
193	861 Maintenance Supervision and Engineering	—	—
194	862 Maintenance of Structures and Improvements	—	—
195	863 Maintenance of Mains	—	—
196	864 Maintenance of Compressor Station Equipment	—	—
197	865 Maintenance of Measuring and Regulating Station Equipment	—	—
198	866 Maintenance of Communication Equipment	—	—
199	867 Maintenance of Other Equipment	**SEE FERC ANNUAL REPORT PAGES 317-325**	
200	TOTAL Maintenance (Total of lines 193 thru 199)	—	—
201	TOTAL Transmission Expenses (Total of lines 191 and 200)	—	—
202	4. DISTRIBUTION EXPENSES		
203	Operation		
204	870 Operation Supervision and Engineering	—	—
205	871 Distribution Load Dispatching	—	—
206	872 Compressor Station Labor and Expenses	—	—
207	873 Compressor Station Fuel and Power	—	—
208	874 Mains and Services Expenses	—	—
209	875 Measuring and Regulating Station Expenses-General	—	—
210	876 Measuring and Regulating Station Expenses-Industrial	—	—
211	877 Measuring and Regulating Station Expenses-City Gas	—	—
212	878 Meter and House Regulator Expenses	—	—
213	879 Customer Installations Expenses	—	—
214	880 Other Expenses	—	—
215	881 Rents	—	—
216	TOTAL Operations (Total of lines 204 thru 215)	—	—
217	Maintenance		
218	885 Maintenance Supervision and Engineering	—	—
219	886 Maintenance of Structures and Improvements	—	—
220	887 Maintenance of Mains	—	—
221	888 Maintenance of Compressor Station Equipment	—	—
222	889 Maintenance of Measuring & Regulating Station Equipment-General	—	—
223	890 Maintenance of Meas. and Reg. Station Equipment-Industrial	—	—
224	891 Maintenance of Meas & Reg Station Equip-City Gate	—	—
225	892 Maintenance of Services	—	—
226	893 Maintenance of Meters and House Regulators	—	—
227	894 Maintenance of Other Equipment	—	—
228	TOTAL Maintenance (Total of lines 218 thru 227)	—	—
229	TOTAL Distribution Expenses (Total of lines 216 and 228)	—	—
230	5. CUSTOMER ACCOUNTS EXPENSES		
231	Operation		
232	901 Supervision	—	—
233	902 Meter Reading Expenses	—	—
234	903 Customer Records and Collection Expenses	—	—
235	904 Uncollectible Accounts	—	—
236	905 Miscellaneous Customer Accounts Expenses	—	—
237	TOTAL Customer Accounts Expenses (Total of lines 232-236)	—	—
238	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSE		
239	Operation		
240	907 Supervision	—	—
241	908 Customer Assistance Expense	—	—
242	909 Informational and Instructional Expenses	—	—
243	910 Miscellaneous Customer Service and Informational Expenses	—	—
244	TOTAL Customer Service & Information Expenses (Total of lines 240 thru 243)	—	—

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STATE OF OREGON ALLOCATED - GAS OPERATION AND MAINTENANCE EXPENSES (Con't)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
245	7. SALES EXPENSES		
246	Operation		
247	911 Supervision	—	—
248	912 Demonstration and Selling Expenses	—	—
249	913 Advertising Expenses	—	—
250	916 Miscellaneous Sales Expenses	**SEE FERC ANNUAL REPORT PAGES 317-325**	
251	TOTAL Sales Expenses (Total of lines 247 thru 250)	—	—
252	8. ADMINISTRATIVE AND GENERAL EXPENSES		
253	Operation		
254	920 Administrative and General Salaries	—	—
255	921 Office Supplies and Expenses	—	—
256	(Less) 922 Administrative Expenses Transferred - Credit	—	—
257	923 Outside Services Employed	—	—
258	924 Property Insurance	—	—
259	925 Injuries and Damages (See Note 1 Below)	—	—
260	926 Employee Pensions and Benefits	—	—
261	927 Franchise Requirements	—	—
262	928 Regulatory Commission Expenses	—	—
263	(Less) 929 Duplicate Charges - Credit	—	—
264	930.1 General Advertising Expenses	—	—
265	930.2 Miscellaneous General Expenses	—	—
266	931 Rents	—	—
267	TOTAL Operation (Total of lines 254 thru 266)	—	—
268	Maintenance		
269	935 Maintenance of General Plant	—	—
270	TOTAL Administrative and General Expenses (Total of lines 267 and 269)	—	—
271	TOTAL Gas O & M Expenses (Total of lines 97,177, 201, 229, 237, 244, 251, and 270)	—	—

STATE OF OREGON ALLOCATED - GAS OPERATION AND MAINTENANCE EXPENSES

Line No.	FUNCTIONAL CLASSIFICATIONS (a)	OPERATION (b)	MAINTENANCE (c)	TOTAL (d)
272	Production			
273	Manufactured Gas			
274	Natural gas:			
275	Production and Gathering			
276	Products Extraction			
277	Exploration and Dev.			
278	TOTAL Natural Gas	**INFORMATION NOT AVAILABLE**		
279	Other Gas Supply Expenses	**SEE FERC ANNUAL REPORT PAGES 317-325**		
280	TOTAL Production			
281	Underground Storage			
282	Other Storage			
283	LNG Terminaling and Processing			
284	Transmission Expenses			
285	Distribution Expenses			
286	Customer Accounts Expenses			
287	Customer Service and Informational Expenses			
288	Sales Expenses			
289	Adm. and General Expenses			
290	TOTAL Gas O. & M. Expenses			

Name of Respondent	This Report is:	Date of Report	Year of Report
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STATE OF OREGON - ALLOCATED DEPRECIATION, DEPLETION, AND AMORTIZATION OF GAS PLANT (Account 403, 404.1, 404.2, 404.3, 405)

(Except Amortization of Acquisitions Adjustments)

Report the amounts of depreciation expense, depletion and amortization for the accounts indicated and classify according to the plant functional groups shown.

Line No.	FUNCTIONAL CLASSIFICATION (a)	DEPRECIATION EXPENSE (ACCOUNT 403) (b)	AMORTIZATION & DEPLETION OF PRODUCING NATURAL GAS LAND & LAND RIGHTS (ACCOUNT 404.1) (c)	AMORTIZATION OF UNDERGROUND STORAGE LAND & LAND RIGHTS (ACCOUNT 404.2) (d)	AMORTIZATION OF OTHER LIMITED-TERM GAS PLANT (ACCOUNT 404.3) (e)	AMORTIZATION OF OTHER GAS PLANT (ACCOUNT 405) (f)	TOTAL (g)
1	Intangible Plant						
2	Production Plant, Manufactured Gas						
3	Production and Gathering Plant, Natural Gas		**N/A - See SITUS schedule at OR 30**				
4	Products Extraction Plant						
5	Underground Gas Storage Plant						
6	Other Storage Plant						
7	Base Load LNG Terminaling and Processing Plant						
8	Transmission Plant						
9	Distribution Plant						
10	General Plant						
11	Common Plant - Gas						
12							
13							
14							
15							
16							
17							
18							
19	TOTAL						

Name of Respondent	This Report is:	Date of Report	Year of Report
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Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

STATE OF OREGON - ALLOCATED TAXES, OTHER THAN INCOME TAXES (Account 408.1)

Line No.	KIND OF TAX (a)	AMOUNT (b)
	SEE FERC ANNUAL REPORT PAGES 262a - 263b	
	TOTAL (Must agree with page 1, line 11)	

Name of Respondent	This Report is:	Date of Report	Year of Report
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Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

STATE OF OREGON - ALLOCATED CALCULATION OF CURRENT FEDERAL INCOME TAX EXPENSE (Account 409.1)

1. Report amounts used to derive current Federal income tax expense, Account 409.1, for the reporting period. If amounts are shown in thousands, show (000) in the heading for column (b).

2. Show amounts increasing taxable income as positive values and amounts decreasing taxable income as negative.

3. Current tax expense on this schedule must match the amount reported on page 1, line 12 of this report. Separately identify adjustments arising from revisions of prior year accruals.

4. Minor amounts of other additions (subtractions) may be grouped.

Line No.	PARTICULARS (Details) (a)	AMOUNT (b)
1	Gas Operating Revenues	
2	Operations and Maintenance Expenses	
3	Taxes, Other than Income	
4	State Income (Excise) Tax	
5	Interest	
6	Federal Income Tax Depreciation	
7	Other Additions (Subtractions) to Derive Taxable Income	
8		
9		
10		
11		
12		
13		
14	**SEE FERC ANNUAL REPORT**	
15	**PAGE 261**	
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	
28	Show Computation of Tax:	

Name of Respondent	This Report is:	Date of Report	Year of Report
	(1) ☒ An Original	(Mo, Da, Yr)	
Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

STATE OF OREGON - ALLOCATED CALCULATION OF CURRENT FEDERAL INCOME TAX EXPENSE (Account 409.1)

1. Report amounts used to derive current Federal income tax expense, Account 409.1, for the reporting period. If amounts are shown in thousands, show (000) in the heading for column (b).

2. Show amounts increasing taxable income as positive values and amounts decreasing taxable income as negative.

3. Current tax expense on this schedule must match the amount reported on page 1, line 13 of this report. Separately identify adjustments arising from revisions of prior year accruals.

4. Minor amounts of other additions (subtractions) may be grouped.

Line No.	PARTICULARS (Details) (a)	AMOUNT (b)
1	Gas Operating Revenues	
2	Operations and Maintenance Expenses	
3	Taxes, Other than Income	
4	Interest	
5	State Income (Excise) Tax Depreciation	
6	Other Additions (Subtractions) to Derive Taxable Income	
7		
8		
9		
10		
11		
12		
13		
14	**SEE FERC ANNUAL REPORT**	
15	**PAGE 261**	
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	
28	Show Computation of Tax:	

Name of Respondent	This Report is:	Date of Report	Year of Report
	(1) ☒ An Original	(Mo, Da, Yr)	
Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

STATE OF OREGON - ALLOCATED ACCUMULATED DEFERRED INCOME TAXES (Account 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. In the space provided:
   (a) identify, by amount and classification, significant items for which deferred taxes are being provided.
   (b) indicate insignificant amounts under Other.

Line No.	ACCOUNT SUBDIVISIONS (a)	BALANCE BEGINNING OF YEAR (b)	CHANGES DURING THE YEAR: AMOUNTS DEBITED ACCOUNT 410.1 (c)	CHANGES DURING THE YEAR: AMOUNTS CREDITED ACCOUNT 410.1 (d)
1	Electric			
2				
3				
4				
5				
6				
7	Other			
8	TOTAL ELECTRIC			
9				
10				
11				
12				
13				
14				
15	Other			
16	TOTAL GAS			
17	Other (Specify)			
18	TOTAL (ACCOUNT 190)			
19	Classification of Totals			
20	Federal Income Tax			
21	State Income Tax			
22	Local Income Tax			

NOT APPLICABLE

Name of Respondent	This Report is:	Date of Report	Year of Report
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Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

STATE OF OREGON - ALLOCATED ACCUMULATED DEFERRED INCOME TAXES (Account 190) (Con't)

3. Beginning balance may be omitted if not readily available. Report gas utility deferred taxes only.
4. Use separate pages as required.

CHANGES DURING THE YEAR		ADJUSTMENTS					
		DEBITS		CREDITS			
AMOUNTS DEBITED ACCOUNT 410.2	AMOUNTS CREDITED ACCOUNT 410.2	ACCT. NO.	AMOUNT	ACCT. NO.	AMOUNT	BALANCE END OF YEAR	Line
(e)	(f)	(g)	(h)	(i)	(j)	(k)	No.
							1
							2
							3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
							15
							16
							17
							18
							19
							20
							21
							22

NOT APPLICABLE

STATE OF OREGON - ALLOCATED ACCUMULATED DEFERRED INCOME TAXES (Account 281)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amortizable property.
2. In the space provided:
   (a) identify, by amount and classification, significant items for which deferred taxes are being provided.
   (b) indicate insignificant amounts under Other.
   (c) Date amortization for tax purposes commenced.
   (d) "Normal" depreciation rate used in computing the deferred tax.

Line No.	ACCOUNT (a)	BALANCE BEGINNING OF YEAR (b)	CHANGES DURING THE YEAR: AMOUNTS DEBITED ACCOUNT 410.1 (c)	CHANGES DURING THE YEAR: AMOUNTS CREDITED ACCOUNT 410.1 (d)
1	Accelerated Amortization (Account 281)			
2	Electric			
3	Defense Facilities			
4	Pollution Control Facilities			
5	Other			
6				
7				
8	TOTAL Electric (Total of lines 3 thru 7)			
9	Gas			
10	Defense Facilities			
11	Pollution Control Facilities			
12	Other			
13				
14				
15	TOTAL Gas (Total of lines 10 thru 14)			
16	Gas (Specify)			
17	TOTAL (Acct 281) Total of 8, 15 & 16)			
18	Classification of TOTAL			
19	Federal Income Tax			
20	State Income Tax			
21	Local Income Tax			

NOT APPLICABLE

Name of Respondent	This Report is:	Date of Report	Year of Report
	(1) ☒ An Original	(Mo, Da, Yr)	
Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

STATE OF OREGON - ALLOCATED ACCUMULATED DEFERRED INCOME TAXES (Account 281) (Con't)

(e) Tax rate used originally defer amounts and the tax rate used during the current year to amortize previous deferrals.

3. Beginning balance may be omitted if not readily available. Report gas utility deferred taxes only.
4. Use separate pages as required.

CHANGES DURING THE YEAR		ADJUSTMENTS					
		DEBITS		CREDITS			
AMOUNTS DEBITED ACCOUNT 410.2	AMOUNTS CREDITED ACCOUNT 410.2	ACCT. NO.	AMOUNT	ACCT. NO.	AMOUNT	BALANCE END OF YEAR	Line
(e)	(f)	(g)	(h)	(i)	(j)	(k)	No.
							1
							2
							3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
							15
							16
							17
							18
							19
							20
							21

NOT APPLICABLE

STATE OF OREGON - ALLOCATED ACCUMULATED DEFERRED INCOME TAXES (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to property not subject to accelerated amortization.

2. In the space provided:

(a) State the general method or methods of liberalized depreciation being used (sum-of-year digits, declining balance, etc.)

(b) Estimated lives (i.e. useful life, guideline life, guideline class life, etc.)

(c) Classes of plant to which each method is being applied and date method was adopted.

Line No.	ACCOUNT SUBDIVISIONS (a)	BALANCE BEGINNING OF YEAR (b)	CHANGES DURING THE YEAR: AMOUNTS DEBITED ACCOUNT 410.1 (c)	CHANGES DURING THE YEAR: AMOUNTS CREDITED ACCOUNT 410.1 (d)
1	Account 282			
2	Electric			
3	Gas			
4	Other			
5	TOTAL (Total of lines 2 thru 4)			
6	Other (Specify)			
7				
8				
9	TOTAL (Acct 282) (Total of 5 thru 8)			
10	Classification of TOTAL			
11	Federal Income Tax			
12	State Income Tax			
13	Local Income Tax			

NOT APPLICABLE

Name of Respondent	This Report is:	Date of Report	Year of Report
	(1) ☒ An Original	(Mo, Da, Yr)	
Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

STATE OF OREGON - ALLOCATED ACCUMULATED DEFERRED INCOME TAXES (Account 282) (Con't)

3. Beginning balance may be omitted if not readily available. Report gas utility deferred taxes only.
4. Use separate pages as required.

CHANGES DURING THE YEAR		ADJUSTMENTS					
AMOUNTS DEBITED ACCOUNT 410.2	AMOUNTS CREDITED ACCOUNT 410.2	DEBITS		CREDITS		BALANCE END OF YEAR	Line
		ACCT. NO.	AMOUNT	ACCT. NO.	AMOUNT		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	No.
							1
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							7
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							9
							10
							11
							12
							13

NOT APPLICABLE

Name of Respondent	This Report is:	Date of Report	Year of Report
	(1) ☒ An Original	(Mo, Da, Yr)	
Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

STATE OF OREGON - ALLOCATED ACCUMULATED DEFERRED INCOME TAXES (Account 283)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.

2. In the space provided below include amounts relating to insignificant items under Other.

Line No.	ACCOUNT SUBDIVISIONS (a)	BALANCE BEGINNING OF YEAR (b)	CHANGES DURING THE YEAR: AMOUNTS DEBITED ACCOUNT 410.1 (c)	CHANGES DURING THE YEAR: AMOUNTS CREDITED ACCOUNT 410.1 (d)
1	Account 283			
2	Electric			
3				
4				
5				
6				
7				
8	Other			
9	TOTAL Electric (Total of 2 thru 8)			
10	Gas			
11				
12				
13				
14				
15				
16	Other			
17	TOTAL Gas (Total of lines 10 thru 16)			
18	Other (Specify)			
19	TOTAL (Acct 283) (Total of 9, 17, & 18)			
20	Classification of TOTAL			
21	Federal Income Tax			
22	State Income Tax			
23	Local Income Tax			

SEE ANNUAL REPORT
PAGES 276 - 277

Name of Respondent	This Report is:	Date of Report	Year of Report
	(1) ☒ An Original	(Mo, Da, Yr)	
Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

STATE OF OREGON - ALLOCATED ACCUMULATED DEFERRED INCOME TAXES (Account 282) (Con't)

3. Beginning balance may be omitted if not readily available. Report gas utility deferred taxes only.
4. Use separate pages as required.

CHANGES DURING THE YEAR		ADJUSTMENTS					
		DEBITS		CREDITS			
AMOUNTS DEBITED ACCOUNT 410.2	AMOUNTS CREDITED ACCOUNT 410.2	ACCT. NO.	AMOUNT	ACCT. NO.	AMOUNT	BALANCE END OF YEAR	Line
(e)	(f)	(g)	(h)	(i)	(j)	(k)	No.
							1
							2
							3
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**SEE ANNUAL REPORT
PAGES 276 - 277**

Name of Respondent	This Report is:	Date of Report	Year of Report
	(1) ☒ An Original	(Mo, Da, Yr)	
Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

STATE OF OREGON - ALLOCATED ACCUMULATED DEFERED INVESTMENT TAX CREDITS (Account 255)

Report below information applicable to Account 255. Explain by footnote any correction to the account balance shown in column (g). Include in column (l) the average period over which the tax credits are amortized.

Line No.	ACCOUNT (a)	BALANCE BEGINNING OF YEAR (b)	DEFERRED FOR YEAR ACCOUNT NO. (c)	DEFERRED FOR YEAR AMOUNT (d)	ALLOCATION TO CURRENT YEAR'S INCOME ACCOUNT NO. (e)	ALLOCATION TO CURRENT YEAR'S INCOME AMOUNT (f)	ADJUSTMENTS (g)	BALANCE END OF YEAR (h)
1								
2								
3								
4								
5								
6								
7								
8								
9	**NONE**							
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12								
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32								
33								

NOTES

Name of Respondent	This Report is:	Date of Report	Year of Report
	(1) ☒ An Original	(Mo, Da, Yr)	
Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

STATE OF OREGON - ALLOCATED ACCUMULATED DEFERED INVESTMENT TAX CREDITS (Account 255)

Report below information applicable to Account 255. Explain by footnote any correction to the account balance shown in column (g). Include in column (l) the average period over which the tax credits are amortized.

Line No.	ACCOUNT (a)	BALANCE BEGINNING OF YEAR (b)	DEFERRED FOR YEAR ACCOUNT NO. (c)	DEFERRED FOR YEAR AMOUNT (d)	ALLOCATION TO CURRENT YEAR'S INCOME ACCOUNT NO. (e)	ALLOCATION TO CURRENT YEAR'S INCOME AMOUNT (f)	BALANCE END OF YEAR (g)	AVERAGE PERIOD OF ALLOCATION TO INCOME (h)
1	Gas Utility							
2	3%							
3	4%							
4	7%							
5	10%							
6	TOTAL							
7	Other (List separately and show 3%, 4%, 7% , 10% and TOTAL							
8								
9								
10								
11								
12								
13	**NONE**							
14								
15								
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STATE OF OREGON - SITUS UTILITY PLANT
SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION

Line No.	ITEM (a)	TOTAL (b)	ELECTRIC (c)	GAS (d)	OTHER (SPECIFY) (e)	OTHER (SPECIFY) (f)	COMMON (g)
1	**UTILITY PLANT**						
2	In Service						
3	Plant in Service (Classified)	2,384,297,194		2,384,297,194			
4	Property Under Capital Leases	—		—			
5	Plant Purchased or Sold	—		—			
6	Completed Construction not Classified	296,355,485		296,355,485			
7	Experimental Plant Unclassified	—		—			
8	TOTAL (Enter total of lines 3 thru 7)	2,680,652,679		2,680,652,679			
9	Leased to Others	—		—			
10	Held for Future Use	970,068		970,068			
11	Construction Work in Progress	157,078,987		157,078,987			
12	Acquisition Adjustments	—		—			
13	TOTAL Utility Plant (Enter total of lines 8 thru 12)	2,838,701,734		2,838,701,734			
14	Accum. Prov. for Depr., Amort., & Depl.	1,192,304,017		1,192,304,017			
15	Net Utility Plant (Line 13 less 14)	1,646,397,717		1,646,397,717			
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION						
17	In Service:						
18	Depreciation	1,140,587,325		1,140,587,325			
19	Amort. and Depl. of Producing Natural Gas Land and Land Rights	—		—			
20	Amort. of Underground Storage Land and Land Rights	28,695		28,695			
21	Amort. of Other Utility Plant	79,129,559		79,129,559			
21.01	Salvage Work In Progress	—		—			
21.02	Less Removal Work in Progress	27,441,562		27,441,562			
22	TOTAL in Service (Lines 18 thru 21)	1,192,304,017		1,192,304,017			
23	Leased to Others						
24	Depreciation	—		—			
25	Amortization and Depletion	—		—			
26	TOTAL Leased to Others (Lines 24 and 25)	—		—			
27	Held for Future Use						
28	Depreciation	—		—			
29	Amortization	—		—			
30	TOTAL Held for Future Use (Lines 28 and 29)	—		—			
31	Abandonment of Leases (Natural Gas)	—		—			
32	Amort. of Plant Acquisition Adjustment	—		—			
33	TOTAL Accumulated Provisions (Should agree with line 14 above) (Lines 22, 26, 30, 31, and 32)	1,192,304,017		1,192,304,017			

STATE OF OREGON - SITUS GAS PLANT IN SERVICE

1. Report below the original cost of gas plant in service according to the prescribed accounts.

2. In addition to Account 101, *Gas Plant in Service (Classified)*, this page and the next include Account 102, *Gas Plant Purchased or Sold*; Account 103, *Experimental Gas Plant Unclassified*; and Account 106, *Completed Construction Not Classified-Gas.*

3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.

4. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.

5. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions or prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on Estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d) reversals of tentative distributions of prior year unclassified retirements. Attach supplemental statement showing the account distributions of theses tentative classifications in column (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at the end of year.

6. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102. In showing the clearance of Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

7. For Account 399, state the nature and use of plant included in this account and if substantial in amount, submit a supplementary statement showing subaccount classification of such plant conforming to the requirements of these pages.

8. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchaser, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date of such filing.

SEE FOLLOWING PAGES

Period Beginning: January 2017
Period Ending: December 2017

Functional Class FERC Plant Account		Beginning Balance	Additions	Retirements	Transfers	Adjustments	Ending Balance*
UTILITY							
Intangible Plant							
301	ORGANIZATION	852	—	—	—	—	852
302	FRANCHISES & CONSENTS	83,496	—	—	—	—	83,496
303.1	COMPUTER SOFTWARE	62,412,418	5,571,243	—	—	13,901	67,997,562
303.2	CUSTOMER INFORMATION SYSTEM	30,488,305	—	—	—	—	30,488,305
303.3	INDUSTRIAL & COMMERCIAL BIL	4,146,951	—	—	—	—	4,146,951
303.4	CRMS	682,893	—	—	—	—	682,893
303.5	POWERPLANT SOFTWARE	—	—	—	—	—	—
	Intangible Plant Subtotal*	97,814,915	5,571,243	—	—	13,901	103,400,059
Production Plant - Oil Gas							
304.1	LAND	24,998	—	—	—	—	24,998
305.2	P P O G STRU & IMPR-SEWER S	—	—	—	—	—	—
305.5	P P O G STRU & IMPR-OTHER Y	13,156	—	—	—	—	13,156
312.3	P P O G FUEL HANDLING AND S	—	—	—	—	—	—
318.3	P P O G LIGHT OIL REFINING	144,896	—	—	—	—	144,896
318.5	P P O G TAR PROCESSING	243,551	—	—	—	—	243,551
325	NATURAL GAS PROD AND GATHER	—	—	—	—	—	—
327	NATURAL GAS PROD & GATHERIN	—	—	—	—	—	—
328	NATURAL GAS PROD AND GATHER	—	—	—	—	—	—
331	NATURAL GAS PROD & GATHERIN	—	—	—	—	—	—
332	NATURAL GAS PROD & GATHERIN	—	—	—	—	—	—
333	NATURAL GAS PROD & GATHERIN	—	—	—	—	—	—
334	NATURAL GAS PROD & GATHERIN	—	—	—	—	—	—
	Production Plant - Oil Gas Subtotal*	426,601	—	—	—	—	426,601
Production Plant - Other							
305.11	GAS PRODUCTION - COTTAGE G	8,320	—	—	—	—	8,320
305.17	STRUCTURES MIXING STATION	46,587	—	—	—	—	46,587
311	P P OTHER-LIQUEFIED PETROLE	—	—	—	—	—	—
311.4	P P OTHER-L P G GRANGER	—	—	—	—	—	—
311.7	LIQUIFIED GAS EQUIPMENT COO	4,033	—	—	—	—	4,033
311.8	LIQUIFIED GAS EQUIPMENT LIN	4,209	—	—	—	—	4,209
319	GAS MIXING EQUIPMENT GASCO	185,448	—	—	—	—	185,448
	Production Plant - Other Subtotal*	248,597	—	—	—	—	248,597

ACCOUNT SUMMARY BY FUNCTIONAL CLASS

NW Natural

Period Beginning: January 2017

Period Ending: December 2017

Functional Class / FERC Plant Account		Beginning Balance	Additions	Retirements	Transfers	Adjustments	Ending Balance*
UTILITY							
Natural Gas Underground Storage							
350.1	LAND	106,549	—	—	—	—	106,549
350.2	RIGHTS-OF-WAY	109,625	—	—	—	—	109,625
351	STRUCTURES AND IMPROVEMENTS	7,208,245	173,825	—	—	—	7,382,069
352	WELLS	20,047,076	—	—	—	—	20,047,076
352.1	STORAGE LEASEHOLD & RIGHTS	3,938,491	—	—	—	—	3,938,491
352.2	RESERVOIRS	7,272,553	—	—	—	—	7,272,553
352.3	NON-RECOVERABLE NATURAL GAS	6,440,890	—	—	—	—	6,440,890
353	LINES	6,552,220	—	—	—	—	6,552,220
354	COMPRESSOR STATION EQUIPMENT	31,351,812	904	—	—	—	31,352,716
355	MEASURING / REGULATING EQUIPM	7,284,199	123,928	—	—	—	7,408,127
356	PURIFICATION EQUIPMENT	297,363	—	—	—	—	297,363
357	OTHER EQUIPMENT	1,332,029	—	—	—	—	1,332,029
	Natural Gas Underground Storage Subtotal*	91,941,052	298,657	—	—	—	92,239,708
Local Storage Plant							
360.11	LAND - LNG LINNTON	83,598	—	—	—	—	83,598
360.12	LAND - LNG NEWPORT	536,675	—	—	—	—	536,675
360.2	LAND - OTHER	106,557	—	—	—	—	106,557
361.11	STRUCTURES & IMPROVEMENTS	5,079,620	14,239	(25,020)	—	—	5,068,838
361.12	STRUCTURES & IMPROVEMENTS	7,562,817	12,958,841	(488,187)	—	(10,019,710)	10,013,761
361.2	STRUCTURES & IMPROVEMENTS -	26,757	—	—	—	—	26,757
362.11	GAS HOLDERS - LNG LINNTON	4,333,166	222,898	—	—	—	4,556,064
362.12	GAS HOLDERS - LNG NEWPORT	5,773,903	153,200	—	—	—	5,927,104
362.2	GAS HOLDERS - LNG OTHER	1,600	—	—	—	—	1,600
363.11	LIQUEFACTION EQUIP. - LINN	3,235,223	100,998	(27,318)	—	—	3,308,902
363.12	LIQUEFACTION EQUIP - NEWPO	7,240,152	40,366	(76,582)	—	3,521,246	10,725,181
363.21	VAPORIZING EQUIP - LINNTON	2,683,660	3,009,406	(316,443)	—	(918,006)	4,458,618
363.22	VAPORIZING EQUIP - NEWPORT	3,677,348	3,429,098	(2,328,558)	—	(1,038,074)	3,739,813
363.31	COMPRESSOR EQUIP - LINNTON	180,903	—	—	—	—	180,903
363.32	COMPRESSOR EQUIPMENT - NE	3,512,434	79,270	—	—	775,010	4,366,715
363.41	MEASURING & REGULATING EQU	1,248,620	285,146	—	—	918,006	2,451,772
363.42	MEASURING & REGULATING EQU	113,414	3,565,809	(9,934)	—	6,620,606	10,289,895
363.5	CNG REFUELING FACILITIES	3,051,295	—	—	—	—	3,051,295
363.6	LNG REFUELING FACILITIES	739,473	—	—	—	—	739,473
	Local Storage Plant Subtotal*	49,187,216	23,859,271	(3,272,043)	—	(140,921)	69,633,523

		Period Beginning:	January 2017
		Period Ending:	December 2017

Functional Class / FERC Plant Account		Beginning Balance	Additions	Retirements	Transfers	Adjustments	Ending Balance*
UTILITY							
Transmission Plant							
365.1	LAND	89,772	—	—	—	—	89,772
365.2	LAND RIGHTS	6,455,177	—	—	—	—	6,455,177
366.3	STRUCTURES & IMPROVEMENTS -	1,546,073	—	—	—	—	1,546,073
367	MAINS	150,281,523	3,130,376	—	—	—	153,411,899
367.21	NORTH MIST TRANSMISSION LI	1,994,582	—	—	—	—	1,994,582
367.22	SOUTH MIST TRANSMISSION LI	14,949,264	—	—	—	—	14,949,264
367.23	SOUTH MIST TRANSMISSION LI	34,881,341	—	—	—	—	34,881,341
367.24	11.7M S MIST TRANS LINE	17,466,182	—	—	—	—	17,466,182
367.25	12M NORTH S MIST TRANS	18,613,651	—	—	—	—	18,613,651
367.26	38M NORTH S MIST TRANS	68,232,676	—	—	—	—	68,232,676
368	TRANSMISSION COMPRESSOR	—	—	—	—	—	—
369	MEASURING & REGULATE STATION	3,969,549	—	—	—	—	3,969,549
370	COMMUNICATION EQUIPMENT	—	—	—	—	—	—
	Transmission Plant Subtotal*	318,479,791	3,130,376	—	—	—	321,610,166
Distribution Plant							
374.1	LAND	75,384	—	—	—	—	75,384
374.2	LAND RIGHTS	1,856,083	—	—	—	—	1,856,083
375	STRUCTURES & IMPROVEMENTS	49,372	—	—	—	—	49,372
376.11	MAINS < 4"	497,181,262	14,478,775	(149,297)	—	42,383	511,553,123
376.12	MAINS 4" & >	446,002,698	12,799,574	(106,198)	—	49,168	458,745,242
377	COMPRESSOR STATION EQUIPMENT	818,380	—	—	—	—	818,380
378	MEASURING & REG EQUIP - GENER	31,319,962	860,056	—	—	—	32,180,018
379	MEASURING & REG EQUIP - GATE	6,307,984	3,285,223	—	—	—	9,593,207
380	SERVICES	670,348,369	28,203,310	(901,906)	—	35,469	697,685,242
381	METERS	76,173,979	2,758,254	(646,811)	—	(1,277,232)	77,008,191
381.1	METERS (ELECTRONIC)	1,696,938	—	—	—	—	1,696,938
381.2	ERT (ENCODER RECEIVER TRANS	33,944,086	1,327,556	(364,930)	—	1,277,232	36,183,943
382	METER INSTALLATIONS	53,359,676	2,803,513	(1,574,900)	—	—	54,588,289
382.1	METER INSTALLATIONS (ELECTR	481,020	—	—	—	—	481,020
382.2	ERT INSTALLATION (ENCODER	8,431,309	—	(70,089)	—	—	8,361,220
383	HOUSE REGULATORS	1,627,270	170,430	—	—	—	1,797,700
386	OTHER PROPERTY ON CUSTOMERS P	—	1,100,432	—	—	—	1,100,432
387.1	CATHODIC PROTECTION TESTING	173,859	—	—	—	—	173,859
387.2	CALORIMETERS @ GATE STATIONS	69,794	—	—	—	—	69,794
387.3	METER TESTING EQUIPMENT	72,671	—	—	—	—	72,671
	Distribution Plant Subtotal*	1,829,990,097	67,787,123	(3,814,131)	—	127,020	1,894,090,110

					Period Beginning:	January 2017
					Period Ending:	December 2017

Functional Class FERC Plant Account	Beginning Balance	Additions	Retirements	Transfers	Adjustments	Ending Balance*
UTILITY						
General Plant						
389 LAND	9,609,258	—	—	—	—	9,609,258
390 STRUCTURES & IMPROVEMENTS	58,238,111	555,492	—	—	—	58,793,603
390.1 SOURCE CONTROL PLANT	18,164,907	442,186	—	—	—	18,607,094
391.1 OFFICE FURNITURE & EQUIPMEN	10,847,175	616,407	—	—	—	11,463,582
391.2 COMPUTERS	21,619,782	8,872,600	(4,117,001)	—	—	26,375,380
391.3 ON SITE BILLING	—	—	—	—	—	—
391.4 CUSTOMER INFORMATION SYSTEM	—	—	—	—	—	—
392 TRANSPORTATION EQUIPMENT	38,026,611	5,641,036	(1,680,877)	—	—	41,986,770
393 STORES EQUIPMENT	119,406	—	—	—	—	119,406
394 TOOLS - SHOP & GARAGE EQUIPUI	9,799,115	1,972,557	—	—	—	11,771,671
395 LABORATORY EQUIPMENT	68,293	—	—	—	—	68,293
396 POWER OPERATED EQUIPMENT	8,811,431	1,446,523	(441,739)	—	—	9,816,215
397 GEN PLANT-COMMUNICATION EQU	88,322	—	—	—	—	88,322
397.1 MOBILE	475,621	—	—	—	—	475,621
397.2 OTHER THAN MOBILE & TELEMET	1,690,854	—	—	—	—	1,690,854
397.3 TELEMETERING - OTHER	4,611,216	—	—	—	—	4,611,216
397.4 TELEMETERING - MICROWAVE	1,646,795	1,206,002	—	—	—	2,852,797
397.5 TELEPHONE EQUIPMENT	490,764	2	—	—	—	490,767
398 GEN PLANT-MISCELLANEOUS EQU	—	—	—	—	—	—
398.1 PRINT SHOP	83,249	—	—	—	—	83,249
398.2 KITCHEN EQUIPMENT	12,812	—	—	—	—	12,812
398.3 JANITORIAL EQUIPMENT	14,873	—	—	—	—	14,873
398.4 INSTALLED IN LEASED BUILDINGS	5,393	—	—	—	—	5,393
398.5 OTHER MISCELLANEOUS EQUIPMENT	66,739	—	—	—	—	66,739
General Plant Subtotal*	184,490,728	20,752,804	(6,239,617)	—	—	199,003,915
Utility Property Grand Total*	2,572,578,996	121,399,473	(13,325,790)	—	—	2,680,652,679

* May not foot due to rounding.

ACCOUNT SUMMARY BY FUNCTIONAL CLASS

NW Natural

Period Beginning: January 2017

Period Ending: December 2017

Functional Class FERC Plant Account		Beginning Balance	Additions	Retirements	Transfers	Adjustments	Ending Balance*
NON-UTILITY							
Intangible Plant							
303.1	COMPUTER SOFTWARE	163,357	—	—	—	—	163,357
303.2	CUSTOMER INFORMATION SYSTEM	61,429	—	—	—	—	61,429
Non Utility	Intangible Plant Subtotal*	224,786	—	—	—	—	224,786
Natural Gas Underground Storage							
352	WELLS	16,940,451	—	—	—	—	16,940,451
352.1	STORAGE LEASEHOLD & RIGHTS	1,020	—	—	—	—	1,020
352.2	RESERVOIRS	3,561,501	—	—	—	—	3,561,501
353	LINES	1,649,744	—	—	—	—	1,649,744
354	COMPRESSOR STATION EQUIPMENT	13,152,395	147,448	—	—	—	13,299,843
355	MEASURING / REGULATING EQUIPM	8,826,808	49,922	—	—	—	8,876,730
357	OTHER EQUIPMENT	63,256	—	—	—	—	63,256
Non Utility	Natural Gas Underground Storage Subtotal*	44,195,176	197,369	—	—	—	44,392,546
Transmission Plant							
368	TRANSMISSION COMPRESSOR	7,723,454	—	—	—	—	7,723,454
Non Utility	Transmission Plant Subtotal*	7,723,454	—	—	—	—	7,723,454
Distribution Plant							
376.12	MAINS 4" & >	878,618	—	—	—	—	878,618
Non Utility	Distribution Plant Subtotal*	878,618	—	—	—	—	878,618
General Plant							
389	LAND	438,739	—	—	—	—	438,739
390	STRUCTURES & IMPROVEMENTS	231,688	6,781	—	—	—	238,469
Non Utility	General Plant Subtotal*	670,427	6,781	—	—	—	677,208

ACCOUNT SUMMARY BY FUNCTIONAL CLASS

NW Natural

Period Beginning: January 2017

Period Ending: December 2017

Functional Class / FERC Plant Account		Beginning Balance	Additions	Retirements	Transfers	Adjustments	Ending Balance*
NON-UTILITY							
Non Utility Other							
121.1	NON-UTIL PROP-DOCK	1,946,033	—	—	—	—	1,946,033
121.2	NON-UTIL PROP-LAND	125,102	—	—	—	—	125,102
121.3	NON-UTIL PROP-OIL ST	3,669,978	965,202	—	—	—	4,635,180
121.7	NON-UTIL PROP-APPL CENTER	61,113	3,793	—	—	—	64,906
121.8	NON-UTIL PROP-STORAGE	96,038	—	—	—	—	96,038
Non Utility	Other*	5,898,264	968,995	—	—	—	6,867,259
	Non Utility Property Grand Total*	59,590,725	1,173,146	—	—	—	60,763,871

* May not foot due to rounding.

Name of Respondent	This Report is:	Date of Report	Year of Report
	(1) ☒ An Original	(Mo, Da, Yr)	
Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

STATE OF OREGON - SITUS GAS PLANT HELD FOR FUTURE USE (Account 105)

1. Report separately each property held for future use at end of the year having an original cost of $100,000 or more. Other items of property held for future use may be grouped provided that the number of properties so grouped is indicated.

2. For property having an original cost of $100,000 or more previously used in utility operations, now held for future use, give in addition to other required information, the date that utility use of such property was discontinued, and the date the original was transferred to Account 105.

Line No.	DESCRIPTION AND LOCATION OF PROPERTY (a)	DATE ORIGINALLY INCLUDED IN THIS ACCOUNT (b)	DATE EXPECTED (c)	BALANCE END OF YEAR (d)
1	Underground Storage	07/2009	Undetermined	127,921
2	Easement	11/2011	Undetermined	136,720
3	Willamette River Crossing - Engineering Costs	05/2015	Undetermined	705,427
4				
5				
6				
7				
8				
9				
10				
11				
12				
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14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30	TOTALS			970,068

Name of Respondent	This Report is:	Date of Report	Year of Report
	(1) ☒ An Original	(Mo, Da, Yr)	
Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

STATE OF OREGON - SITUS CONSTRUCTION WORK IN PROGRESS - GAS (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (Account 107)

2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstration (see Account 107 of the Uniform System of Accounts).

3. Minor projects (less than $1,000,000) may be grouped.

Line No.	DESCRIPTION OF PROJECT (a)	CONSTRUCTION WORK IN PROGRESS - GAS (ACCOUNT 107) (b)	ESTMATED ADDITIONAL COST OF PROJECT (c)
1	North Mist Expansion Project	113,165,780	18,834,220
2	Other	14,069,708	5,260,011
3	Misc IS Projects	13,770,451	6,312,140
4	Mains and Service Jobs	13,225,320	16,343,962
5	Misc Facilities Projects	1,447,556	30,522,645
6	Portland LNG Readiness	1,047,455	2,663,025
7	Newport LNG Readiness	352,717	3,984,559
8			
9			
10			
11			
12			
13			
14			
15			
16			
17			
18			
19			
20			
21			
22			
23			
24			
25			
26			
27			
28			
29			
30	TOTALS	157,078,987	83,920,562

STATE OF OREGON - SITUS ACCUMULATED PROVISION FOR DEPRECIATION OF GAS UTILITY PLANT (Account 108)

1. Explain in a footnote any important adjustments during year.

2. Explain in a footnote any difference between the amount for book cost of plant retired, line 11, column (c), and that reported for gas plant in service pages 24-27, column (d), excluding retirements of non-depreciable property.

3. The provisions of Account 108 of the Uniform System of Accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.

4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

SEE FOLLOWING PAGES

Period Beginning: January 2017
Period Ending: December 2017

Functional Class FERC Plant Account		Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Loss/(Gain)	Ending Reserve*
UTILITY									
Intangible Plant									
301	ORGANIZATION	—	—	—	—	—	—	—	—
302	FRANCHISES & CONSENTS	—	—	—	—	—	—	—	—
303.1	COMPUTER SOFTWARE	23,266,305	2,791,161	—	—	—	154	—	26,057,620
303.2	CUSTOMER INFORMATION SYSTEM	30,485,095	—	—	—	—	—	—	30,485,095
303.3	INDUSTRIAL & COMMERCIAL BIL	4,146,951	—	—	—	—	—	—	4,146,951
303.4	CRMS	683,689	(797)	—	—	—	—	—	682,893
303.5	POWERPLANT SOFTWARE	—	—	—	—	—	—	—	—
	Intangible Plant Subtotal*	58,582,040	2,790,365	—	—	—	154	—	61,372,559
Production Plant - Oil Gas									
304.1	LAND	—	—	—	—	—	—	—	—
305.2	P P O G STRU & IMPR-SEWER S	—	—	—	—	—	—	—	—
305.5	P P O G STRU & IMPR-OTHER Y	13,814	—	—	—	—	—	—	13,814
312.3	P P O G FUEL HANDLING AND S	—	—	—	—	—	—	—	—
318.3	P P O G LIGHT OIL REFINING	152,141	—	—	—	—	—	—	152,141
318.5	P P O G TAR PROCESSING	255,729	—	—	—	—	—	—	255,729
325	NATURAL GAS PROD AND GATHER	—	—	—	—	—	—	—	—
327	NATURAL GAS PROD & GATHERIN	—	—	—	—	—	—	—	—
328	NATURAL GAS PROD AND GATHER	—	—	—	—	—	—	—	—
331	NATURAL GAS PROD & GATHERIN	—	—	—	—	—	—	—	—
332	NATURAL GAS PROD & GATHERIN	—	—	—	—	—	—	—	—
333	NATURAL GAS PROD & GATHERIN	—	—	—	—	—	—	—	—
334	NATURAL GAS PROD & GATHERIN	—	—	—	—	—	—	—	—
	Production Plant - Oil Gas Subtotal*	421,683	—	—	—	—	—	—	421,683
Production Plant - Other									
305.11	GAS PRODUCTION - COTTAGE G	8,736	—	—	—	—	—	—	8,736
305.17	STRUCTURES MIXING STATION	51,246	—	—	—	—	—	—	51,246
311	P P OTHER-LIQUEFIED PETROLE	—	—	—	—	—	—	—	—
311.4	P P OTHER-L P G GRANGER	—	—	—	—	—	—	—	—
311.7	LIQUIFIED GAS EQUIPMENT COO	8,066	—	—	—	—	—	—	8,066
311.8	LIQUIFIED GAS EQUIPMENT LIN	6,585	—	—	—	—	—	—	6,585
319	GAS MIXING EQUIPMENT GASCO	194,720	—	—	—	—	—	—	194,720
	Production Plant - Other Subtotal*	269,353	—	—	—	—	—	—	269,353

RESERVE BALANCES AND ACTIVITY BY FUNCTIONAL CLASS
NW NATURAL

Period Beginning: January 2017
Period Ending: December 2017

Functional Class / FERC Plant Account		Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Loss/(Gain)	Ending Reserve
UTILITY									
Natural Gas Underground Storage									
350.1	LAND	—	—	—	—	—	—	—	—
350.2	RIGHTS-OF-WAY	26,919	1,776	—	—	—	—	—	28,695
351	STRUCTURES AND IMPROVEMENTS	2,665,916	123,910	—	—	—	—	—	2,789,826
352	WELLS	11,390,537	414,974	—	—	—	—	—	11,805,512
352.1	STORAGE LEASEHOLD & RIGHTS	1,593,616	76,801	—	—	—	—	—	1,670,417
352.2	RESERVOIRS	2,384,777	146,178	—	—	—	—	—	2,530,955
352.3	NON-RECOVERABLE NATURAL GAS	3,319,796	121,089	—	—	—	—	—	3,440,885
353	LINES	3,041,105	134,967	—	—	—	—	—	3,176,072
354	COMPRESSOR STATION EQUIPMENT	17,881,027	848,770	—	—	—	—	—	18,729,797
355	MEASURING / REGULATING EQUIPM	4,424,715	158,994	—	—	—	—	—	4,583,709
356	PURIFICATION EQUIPMENT	225,070	7,375	—	—	—	—	—	232,445
357	OTHER EQUIPMENT	827,385	30,370	—	—	—	—	—	857,756
	Natural Gas Underground Storage Subtotal*	47,780,863	2,065,204	—	—	—	—	—	49,846,067
Local Storage Plant									
360.11	LAND - LNG LINNTON	—	—	—	—	—	—	—	—
360.12	LAND - LNG NEWPORT	—	—	—	—	—	—	—	—
360.2	LAND - OTHER	—	—	—	—	—	—	—	—
361.11	STRUCTURES & IMPROVEMENTS	2,189,212	276,314	(25,020)	—	—	—	—	2,440,507
361.12	STRUCTURES & IMPROVEMENTS	2,477,560	393,476	(488,187)	—	—	(104,623)	—	2,278,225
361.2	STRUCTURES & IMPROVEMENTS -	10,959	466	—	—	—	—	—	11,425
362.11	GAS HOLDERS - LNG LINNTON	2,241,345	102,509	—	—	—	—	—	2,343,855
362.12	GAS HOLDERS - LNG NEWPORT	5,578,002	157,571	—	—	—	—	—	5,735,573
362.2	GAS HOLDERS - LNG OTHER	1,193	21	—	—	—	—	—	1,213
363.11	LIQUEFACTION EQUIP. - LINN	2,495,345	93,732	(27,318)	—	—	—	—	2,561,759
363.12	LIQUEFACTION EQUIP - NEWPO	7,119,569	67,826	(76,582)	—	—	39,178	—	7,149,990
363.21	VAPORIZING EQUIP - LINNTON	2,662,282	55,948	(316,443)	—	—	(5,293)	—	2,396,494
363.22	VAPORIZING EQUIP - NEWPORT	2,615,653	3,794	(2,328,558)	—	—	(156)	—	290,733
363.31	COMPRESSOR EQUIP - LINNTON	206,897	—	—	—	—	—	—	206,897
363.32	COMPRESSOR EQUIPMENT - NE	367,637	177,133	—	—	—	8,596	—	553,366
363.41	MEASURING & REGULATING EQU	604,762	526	—	—	—	5,293	—	610,581
363.42	MEASURING & REGULATING EQU	118,309	26,008	(9,934)	—	—	55,772	—	190,155
363.5	CNG REFUELING FACILITIES	1,360,531	31,733	—	—	—	—	—	1,392,264
363.6	LNG REFUELING FACILITIES	739,473	—	—	—	—	—	—	739,473
	Local Storage Plant Subtotal*	30,788,729	1,387,056	(3,272,043)	—	—	(1,232)	—	28,902,511

RESERVE BALANCES AND ACTIVITY BY FUNCTIONAL CLASS
NW NATURAL

Period Beginning: January 2017
Period Ending: December 2017

Functional Class FERC Plant Account		Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Loss/(Gain)	Ending Reserve*
UTILITY									
Transmission Plant									
365.1	LAND	—	—	—	—	—	—	—	—
365.2	LAND RIGHTS	1,886,332	122,003	—	—	—	—	—	2,008,335
366.3	STRUCTURES & IMPROVEMENTS -	298,976	30,148	—	—	—	—	—	329,124
367	MAINS	27,741,190	4,662,977	—	—	—	—	—	32,404,168
367.21	NORTH MIST TRANSMISSION LI	1,079,882	50,054	—	—	—	—	—	1,129,936
367.22	SOUTH MIST TRANSMISSION LI	10,301,352	367,672	—	—	—	—	—	10,669,024
367.23	SOUTH MIST TRANSMISSION LI	12,757,392	931,147	—	—	—	—	—	13,688,539
367.24	11.7M S MIST TRANS LINE	5,271,948	452,281	—	—	—	—	—	5,724,229
367.25	12M NORTH S MIST TRANS	5,307,360	485,717	—	—	—	—	—	5,793,077
367.26	38M NORTH S MIST TRANS	19,647,514	1,773,685	—	—	—	—	—	21,421,198
368	TRANSMISSION COMPRESSOR	(9)	—	—	—	—	—	—	(9)
369	MEASURING & REGULATE STATION	1,444,979	106,379	—	—	—	—	—	1,551,358
370	COMMUNICATION EQUIPMENT	—	—	—	—	—	—	—	—
	Transmission Plant Subtotal*	85,736,915	8,982,063	—	—	—	—	—	94,718,978
Distribution Plant									
374.1	LAND	—	—	—	—	—	—	—	—
374.2	LAND RIGHTS	1,399,855	139,206	—	—	—	—	—	1,539,062
375	STRUCTURES & IMPROVEMENTS	49,724	200	—	—	—	—	—	49,924
376.11	MAINS < 4"	275,821,450	12,553,781	(149,297)	(814,137)	9,405	360	—	287,421,562
376.12	MAINS 4" & >	185,635,135	10,911,719	(106,198)	(706,632)	27,222	417	—	195,761,663
377	COMPRESSOR STATION EQUIPMENT	630,397	19,068	—	—	—	—	—	649,465
378	MEASURING & REG EQUIP - GENER	10,690,354	678,641	—	—	—	—	—	11,368,995
379	MEASURING & REG EQUIP - GATE	1,371,082	336,973	—	—	—	—	—	1,708,055
380	SERVICES	356,705,173	18,486,380	(901,906)	(1,206,777)	—	301	—	373,083,170
381	METERS	19,278,942	1,776,866	(646,811)	—	—	(50,607)	—	20,358,390
381.1	METERS (ELECTRONIC)	1,313,599	339,434	—	—	—	—	—	1,653,033
381.2	ERT (ENCODER RECEIVER TRANS	14,826,889	2,295,714	(364,930)	—	—	50,607	—	16,808,280
382	METER INSTALLATIONS	5,987,197	1,277,976	(1,574,900)	—	—	—	—	5,690,273
382.1	METER INSTALLATIONS (ELECTR	52,024	11,490	—	—	—	—	—	63,514
382.2	ERT INSTALLATION (ENCODER	4,313,300	559,096	(70,089)	—	—	—	—	4,802,308
383	HOUSE REGULATORS	208,147	48,792	—	—	—	—	—	256,940
386	OTHER PROPERTY ON CUSTOMERS P	—	—	—	—	—	—	—	—
387.1	CATHODIC PROTECTION TESTING	141,431	956	—	—	—	—	—	142,388
387.2	CALORIMETERS @ GATE STATIONS	69,794	—	—	—	—	—	—	69,794
387.3	METER TESTING EQUIPMENT	72,671	—	—	—	—	—	—	72,671
	Distribution Plant Subtotal*	878,567,164	49,436,294	(3,814,131)	(2,727,547)	36,627	1,078	—	921,499,486

RESERVE BALANCES AND ACTIVITY BY FUNCTIONAL CLASS

NW NATURAL

Period Beginning: January 2017

Period Ending: December 2017

Functional Class / FERC Plant Account		Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Loss/(Gain)	Ending Reserve*
UTILITY									
General Plant									
389	LAND	437,351	—	—	—	—	—	—	437,351
390	STRUCTURES & IMPROVEMENTS	9,434,981	1,139,976	—	—	—	—	—	10,574,957
390.1	SOURCE CONTROL PLANT	3,173,732	964,525	—	—	—	—	—	4,138,257
391.1	OFFICE FURNITURE & EQUIPMEN	7,306,682	881,568	—	—	—	—	—	8,188,251
391.2	COMPUTERS	16,146,225	4,188,715	(4,117,001)	—	—	—	—	16,217,939
391.3	ON SITE BILLING	—	—	—	—	—	—	—	—
391.4	CUSTOMER INFORMATION SYSTEM	—	—	—	—	—	—	—	—
392	TRANSPORTATION EQUIPMENT	8,964,669	1,995,265	(1,680,877)	—	223,715	—	—	9,502,772
393	STORES EQUIPMENT	119,406	—	—	—	—	—	—	119,406
394	TOOLS - SHOP & GARAGE EQUIPUI	3,417,736	748,970	—	—	4,706	—	—	4,171,412
395	LABORATORY EQUIPMENT	68,293	—	—	—	—	—	—	68,293
396	POWER OPERATED EQUIPMENT	2,811,997	189,861	(441,739)	—	129,938	—	—	2,690,056
397	GEN PLANT-COMMUNICATION EQU	33,654	6,545	—	—	—	—	—	40,199
397.1	MOBILE	407,625	3,234	—	—	—	—	—	410,859
397.2	OTHER THAN MOBILE & TELEMET	1,690,854	—	—	—	—	—	—	1,690,854
397.3	TELEMETERING - OTHER	2,978,465	3,228	—	—	—	—	—	2,981,693
397.4	TELEMETERING - MICROWAVE	950,261	25,997	—	—	—	—	—	976,258
397.5	TELEPHONE EQUIPMENT	252,246	79,749	—	—	—	—	—	331,995
398	GEN PLANT-MISCELLANEOUS EQU	—	—	—	—	—	—	—	—
398.1	PRINT SHOP	83,249	—	—	—	—	—	—	83,249
398.2	KITCHEN EQUIPMENT	3,612	525	—	—	—	—	—	4,137
398.3	JANITORIAL EQUIPMENT	14,873	—	—	—	—	—	—	14,873
398.4	INSTALLED IN LEASED BUILDINGS	5,393	—	—	—	—	—	—	5,393
398.5	OTHER MISCELLANEOUS EQUIPMENT	66,739	—	—	—	—	—	—	66,739
	General Plant Subtotal*	58,368,042	10,228,159	(6,239,617)	—	358,359	—	—	62,714,942
	Utility Property Grand Total*	1,160,514,789	74,889,141	(13,325,790)	(2,727,547)	394,986	—	—	1,219,745,579
NON UTILITY									
Intangible Plant									
303.1	COMPUTER SOFWARE	45,293	7,041	—	—	—	—	—	52,333
303.2	CUSTOMER INFORMATION SYSTEM	42,228	4,275	—	—	—	—	—	46,503
Non Utility	Intangible Plant Subtotal*	87,520	11,316	—	—	—	—	—	98,837

RESERVE BALANCES AND ACTIVITY BY FUNCTIONAL CLASS
NW NATURAL

Period Beginning: **January 2017**
Period Ending: **December 2017**

Functional Class FERC Plant Account		Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Loss/(Gain)	Ending Reserve*
NON UTILITY									
Natural Gas Underground Storage									
352	WELLS	3,599,205	350,667	—	—	—	—	—	3,949,872
352.1	STORAGE LEASEHOLD & RIGHTS	201	20	—	—	—	—	—	221
352.2	RESERVOIRS	807,038	69,449	—	—	—	—	—	876,487
353	LINES	354,310	33,982	—	—	—	—	—	388,292
354	COMPRESSOR STATION EQUIPMENT	4,081,273	381,685	—	—	—	—	—	4,462,958
355	MEASURING / REGULATING EQUIPM	1,919,365	192,570	—	—	—	—	—	2,111,935
357	OTHER EQUIPMENT	10,156	1,442	—	—	—	—	—	11,598
Non Utility	Natural Gas Underground Storage Subtotal*	10,771,549	1,029,816	—	—	—	—	—	11,801,365
Transmission Plant									
368	TRANSMISSION COMPRESSOR	2,087,175	238,655	—	—	—	—	—	2,325,830
Non Utility	Transmission Plant Subtotal*	2,087,175	238,655	—	—	—	—	—	2,325,830
Distribution Plant									
376.12	MAINS 4" & >	214,477	21,258	—	—	—	—	—	235,735
Non Utility	Distribution Plant Subtotal*	214,477	21,258	—	—	—	—	—	235,735
General Plant									
389	LAND	—	—	—	—	—	—	—	—
390	STRUCTURES & IMPROVEMENTS	30,041	4,280	—	—	—	—	—	34,322
Non Utility	General Plant Subtotal*	30,041	4,280	—	—	—	—	—	34,322
Non Utility Other									
121.1	NON-UTIL PROP-DOCK	1,947,067	—	—	—	—	—	—	1,947,067
121.2	NON-UTIL PROP-LAND	—	—	—	—	—	—	—	—
121.3	NON-UTIL PROP-OIL ST	2,223,571	14,159	—	—	—	—	—	2,237,730
121.7	NON-UTIL PROP-APPL CENTER	34,262	4,294	—	—	—	—	—	38,557
121.8	NON-UTIL PROP-STORAGE	(1)	—	—	—	—	—	—	(1)
Non Utility	Other*	4,204,899	18,453	—	—	—	—	—	4,223,352
	Non Utility Property Grand Total*	17,395,661	1,323,778	—	—	—	—	—	18,719,439

Period Beginning: **January 2017**
Period Ending: **December 2017**

Functional Class FERC Plant Account	Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Loss/(Gain)	Ending Reserve
TOTAL SUMMARY ALL UTILITY DEPRECIATION RESERVES		**12/31/2017**						
UTILITY								
108010	**(41,305,966)**							
108011	**929,970,214**							
108012	**12,544,108**							
108013	**(3,087,536)**							
108014	**(606,910)**							
108015	**2,818,787**							
108100	**—**							
108102	**327,250,064**							
108002	**(8,386,166)**							
108003	**63,377**							
108004	**485,607**							
108666	**—**							
SUBTOTAL*		**1,219,745,579**						
ADD:								
108001 REMOVAL WORK IN PROCESS		**(27,441,562)**						
TOTAL UTILITY DEPRECIATION*		**1,192,304,017**						
TOTAL SUMMARY ALL NON-UTILITY RESERVES DEPRECIATION								
NON UTILITY								
122026	**1,034**							
122027	**4,355,478**							
122028	**13,671,824**							
122029	**(531,316)**							
122100	**—**							
122102	**1,313,777**							
122002	**(91,357)**							
TOTAL NON UTILITY DEPRECIATION*		**18,719,441**						

* May not foot due to rounding.

Name of Respondent	This Report is:	Date of Report	Year of Report
	(1) ☒ An Original	(Mo, Da, Yr)	
Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

STATE OF OREGON - ALLOCATED
SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION

Line No.	ITEM (a)	TOTAL (b)	ELECTRIC (c)	GAS (d)	OTHER (SPECIFY) (e)	OTHER (SPECIFY) (f)	COMMON (g)
1	**UTILITY PLANT**						
2	In Service						
3	Plant in Service (Classified)						
4	Property Under Capital Leases						
5	Plant Purchased or Sold						
6	Completed Construction not Classified		**N/A - See SITUS schedule at OR 23**				
7	Experimental Plant Unclassified						
8	TOTAL (Enter total of lines 3 thru 7)						
9	Leased to Others						
10	Held for Future Use						
11	Construction Work in Progress						
12	Acquisition Adjustments						
13	TOTAL Utility Plant (Enter total of lines 8 thru 12)						
14	Accum. Prov. for Depr., Amort., & Depl.						
15	Net Utility Plant (Line 13 less 14)						
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION						
17	In Service:						
18	Depreciation						
19	Amort. and Depl. of Producing Natural Gas Land and Land Rights						
20	Amort. of Underground Storage Land and Land Rights						
21	Amort. of Other Utility Plant						
21.01	Salvage Work In Progress						
21.02	Less Removal Work in Progress						
22	TOTAL in Service (Lines 18 thru 21)						
23	Leased to Others						
24	Depreciation						
25	Amortization and Depletion						
26	TOTAL Leased to Others (Lines 24 and 25)						
27	Held for Future Use						
28	Depreciation						
29	Amortization						
30	TOTAL Held for Future Use (Lines 28 and 29)						
31	Abandonment of Leases (Natural Gas)						
32	Amort. of Plant Acquisition Adjustment						
33	TOTAL Accumulated Provisions (Should agree with line 14 above) (Lines 22, 26, 30, 31, and 32)						

Name of Respondent	This Report is:	Date of Report	Year of Report
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Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

STATE OF OREGON - ALLOCATED GAS PLANT IN SERVICE

1. Report below the original cost of gas plant in service

2. In addition to Account 101, Gas Plant In Service (Classified), this page and the next include Account 102,Gas Plant Purchased or Sold, Account 103, Completed Construction Not Classified - Gas.

3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.

4. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.

5. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions or prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d)a tentative distribution of such retirements, on Estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d) reversals of tentative distributions of prior year unclassified retirements. Attach supplemental statement showing the account distributions of these tentative classifications in column (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and106 will avoid serious omissions of the reported amount of respondent's plant actually in service at the end of the year. **(Continued on page 33)**

Line No.	Account (a)	BALANCE BEGINNING OF YEAR (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	BALANCE END OF YEAR (g)
1	1. Intangible Plant						
2	301 Organization						
3	302 Franchises and Consents						
4	303 Miscellaneous Intangible Plant						
5	TOTAL Intangible Plant						
6	2. Production Plant						
7	Natural Gas Production & Gathering Plant						
8	325.1 Producing Lands						
9	325.2 Producing Leaseholds	**N/A - See SITUS schedule at OR 24 - 27**					
10	325.3 Gas Rights						
11	325.4 Rights-of-Way						
12	325.5 Other Land and Land Rights						
13	326 Gas Well Structures						
14	327 Field Compressor Station Structures						
15	328 Field Meas. And Reg. Sta. Structures						
16	329 Other Structures						
17	330 Producing Gas Wells - Well Construction						
18	331 Producing Gas Wells - Well Equipment						
19	332 Field Lines						
20	333 Field Compressor Station Equipment						
21	334 Field Mess. And Reg. Sta. Equipment						
22	335 Drilling and Cleaning Equipment						
23	336 Purification Equipment						
24	337 Other Equipment						
25	338 Unsuccessful Explor. & Devel. Costs						
26	TOTAL Production & Gathering Plant						
27	Products Extraction Plant						
28	340 Land and Land Rights						
29	341 Structures and Improvements						
30	342 Extraction and Refining Equipment						
31	343 Pipe lines						
32	344 Extracted Products Storage Equipment						

Name of Respondent	This Report is:	Date of Report	Year of Report
	(1) ☒ An Original	(Mo, Da, Yr)	
Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

STATE OF OREGON - ALLOCATED GAS PLANT IN SERVICE (CONT'D)

6. Show in column (f) reclassifications or transfers within utility plant accounts.Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account102. In showing the clearance of Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments,etc. and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

7. For account 399, state the nature and use of plant included in this account and if substantial amount, submit a supplementary statement showing subaccount classification of such plant conforming to the requirements of these pages.

8. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchaser, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date of such filing.

Line No.	Account (a)	BALANCE BEGINNING OF YEAR (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	BALANCE END OF YEAR (g)
	2. Production Plant (Con't) Products Extraction Plant (Con't)						
33	345 Compressor Equipment						
34	345 Gas Meas. And Reg. Equipment						
35	347 Other Equipment						
36	TOTAL Products Extraction Plant						
37	TOTAL Nat. Gas Production Plant	**N/A - See SITUS schedule at OR 24 - 27**					
38	Mfd. Gas Prod. Plant (Submit Suppl. Stmt)						
39	TOTAL Production Plant						
40	3. Natural Gas Storage & Proc. Plant						
41	Underground Storage Plant						
42	350.1 Land						
43	350.2 Rights-of-Way						
44	351 Structures & Improvements						
45	352 Wells						
46	352.1 Storage Leaseholds & Rights						
47	352.2 Reservoirs						
48	352.3 Non-recoverable Natural Gas						
49	353 Lines						
50	354 Compressor Station Equipment						
51	355 Measuring & Reg. Equipment						
52	356 Purification Equipment						
53	357 Other Equipment						
54	TOTAL Underground Storage Plant						
55	Other Storage Plant						
56	360 Land and Land Rights						
57	361 Structures and Improvements						
58	362 Gas Holders						
59	363 Purification Equipment						
60	363.1 Liquefaction Equipment						
61	363.2 Vaporizing Equipment						
62	363.3 Compressor Equipment						
63	363.4 Meas. And Reg. Equipment						
64	363.5 Other Equipment						
65	TOTAL Other Storage Plant						

STATE OF OREGON - ALLOCATED GAS PLANT IN SERVICE (CONT'D)

Line No.	Account (a)	BALANCE BEGINNING OF YEAR (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	BALANCE END OF YEAR (g)
66	Base Load Liquefied Natural Gas Terminaling and Processing Plant						
67	364.1 Land and Land Rights						
68	364.2 Structures and Improvements						
69	364.3 LNG Processing Terminal Equipment						
70	364.4 LNG Transportation Equipment						
71	364.5 Measuring and Regulating Equipment	**N/A - See SITUS schedule at OR 24 - 27**					
72	364.6 Compressor Station Equipment						
73	364.7 Communications Equipment						
74	364.8 Other Equipment						
75	TOTAL Base Load Liquefied Natural						
76	Gas, Terminaling, & Processing Plant						
77	TOTAL Nat. Gas Storage & Proc. Plant						
78	4. Transmission Plant						
79	365.1 Land and Land Rights						
80	365.2 Rights-of-Way						
81	366 Structures and Improvements						
82	367 Mains						
83	368 Compressor Station Equipment						
84	369 Measuring and Reg. Sta. Equipment						
85	370 Communication Equipment						
86	371 Other Equipment						
87	TOTAL Transmission Plant						
88	5. Distribution Plant						
89	374 Land and Land Rights						
90	375 Structures and Improvements						
91	376 Mains						
92	377 Compressor Station Equipment						
93	378 Meas. And Reg. Sta. Equip. - General						
94	379 Meas. And Reg. Sta. Equip. - City Gate						
95	380 Services						
96	381 Meters						
97	382 Meter Installations						
98	383 House Regulators						
99	384 House Reg. installations						
100	385 Industrial Meas. & Reg. Sta. Equip						
101	386 Other Prop. On Customers' premises						
102	387 Other Equipment						
103	TOTAL Distribution Plant						

STATE OF OREGON - ALLOCATED GAS PLANT IN SERVICE (CONT'D)

Line No.	Account (a)	BALANCE BEGINNING OF YEAR (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	BALANCE END OF YEAR (g)
104	6. General Plant						
105	389 Land and Land Rights						
106	390 Structures and Improvements						
107	391 Office Furniture and Equipment						
108	392 Transportation Equipment	N/A - See SITUS schedule at OR 24 - 27					
109	393 Store Equipment						
110	394 Tools, Shop, and Garage Equipment						
111	395 Laboratory Equipment						
112	396 Power Operated Equipment						
113	397 Communication Equipment						
114	398 Miscellaneous Equipment						
115	Subtotal						
116	399 Other Intangible Property						
117	TOTAL General Plant						
118	TOTAL (Accounts 101 and 106)						
119	Gas Plant Purchased (See Instr. 8)						
120	(Less) Gas Plant Sold (See Instr. 8)						
121	Experimental Gas Plant Unclassified						
122	TOTAL Gas Plant In Service						

Name of Respondent	This Report is:	Date of Report	Year of Report
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Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

STATE OF OREGON - ALLOCATED GAS PLANT HELD FOR FUTURE USE (Account 105)

1. Report separately each property held for future use at end of the year having an original cost of $100,000 or more. Other items of property held for future use may be grouped provided that the number of properties so grouped is indicated.

2. For property having an original cost of $100,000 or more previously used in utility operations, now held for future use, give in addition to other required information, the date that utility use of such property was discontinued, and the date the original was transferred to Account 105.

Line No.	DESCRIPTION AND LOCATION OF PROPERTY (a)	DATE ORIGINALLY INCLUDED IN THIS ACCOUNT (b)	DATE EXPECTED (c)	BALANCE END OF YEAR (d)
1				
2				
3				
4	**N/A - See SITUS schedule at OR 28**			
5				
6				
7				
8				
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27				
28				
29				
30	TOTALS			—

Name of Respondent	This Report is:	Date of Report	Year of Report
	(1) ☒ An Original	(Mo, Da, Yr)	
Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

STATE OF OREGON - ALLOCATED CONSTRUCTION WORK IN PROGRESS - GAS (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (Account 107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstration (see Account 107 of the Uniform System of Accounts).
3. Minor projects (less than $1,000,000) may be grouped.

Line No.	DESCRIPTION OF PROJECT (a)	CONSTRUCTION WORK IN PROGRESS - GAS (ACCOUNT 107) (b)	ESTMATED ADDITIONAL COST OF PROJECT (c)
1			
2			
3			
4	**N/A - See SITUS schedule at OR 29**		
5			
6			
7			
8			
9			
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21			
22			
23			
24			
25			
26			
27			
28			
29			
30	TOTALS		

STATE OF OREGON - ALLOCATED ACCUMULATED PROVISION FOR DEPRECIATION OF GAS UTILITY PLANT (Account 108)

1. Explain in a footnote any important adjustments during the year.

2.Explain in a footnote any difference between the amount for book cost of plant retired, line 11, column (c), and that reported for gas plant in service, pages 32-35, column (d)excluding retirements of non-depreciable property.

3.The provisions of Account 108 of the Uniform System of Accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year-end in the appropriate functional classifications.

4.Show separately interest credits under a sinking fund of similar method of depreciation accounting.

Section A. Balances and Changes During Year

Line No.	ITEM (a)	TOTAL (d+d+e) (b)	GAS PLANT IN SERVICE (c)	GAS PLANT HELD FOR FUTURE USE (d)	GAS PLANT LEASED TO OTHERS (e)
1	Balance Beginning of Year				
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense				
4	(413) Exp. Of Gas Plt. Lease to Others				
5	Transportation Expenses - Clearing				
6	Other Clearing Accounts				
7	Other Accounts (Specify):	**N/A - See SITUS schedule at OR 30**			
8					
9	Total Deprec. Prov. For Year (Enter total of lines 3-8)				
10	Net Charges for Plant Retired:				
11	Book Cost of Plant Retired				
12	Cost of Removal				
13	Salvage (Credit)				
14	TOTAL Net Charges for Plant Ret. (Enter Total of lines 11-13)				
15	Other Debit or Credit Items (Describe):				
16					
17	Balance End of Year (Enter Total of Lines 1,9, 14, 15,& 16)				

Section B. Balances at End of Year According to Functional Classifications

Line No.	ITEM (a)	TOTAL (d+d+e) (b)	GAS PLANT IN SERVICE (c)	GAS PLANT HELD FOR FUTURE USE (d)	GAS PLANT LEASED TO OTHERS (e)
18	Production - Manufactured Gas				
19	Prod. And Gathering - Natural Gas				
20	Products Extraction - Natural Gas				
21	Underground Gas Storage				
22	Other Storage Plant				
23	Base Load LNG Term and Proc. Plt.				
24	Transmission				
25	Distribution				
26	General				
27	TOTAL (Total of Lines 18 thru 26)				

Name of Respondent	This Report is:	Date of Report	Year of Report
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Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

STATE OF OREGON - GAS STORED (Account 117, 164.1, 164.2 and 164.3)

1. Report below the information called for concerning inventories of gas stored.

2. The Uniform System of Accounts provides that inventory cost records be maintained on a consolidated basis for all storage projects with separate records showing the Mcf of inputs and withdrawals and balance for each project, except under certain specified circumstances. If the respondent's inventory cost records are not maintained on a consolidated basis for all storage projects, furnish an explanation of the accounting followed and reason for any deviation from the general basis provided by the Uniform System of Accounts. Separate schedules on this schedule form should be furnished for each group of storage projects for which separate inventory cost records are maintained.

3. If during the year adjustment was made of the stored gas inventory, such as to correct for cumulative inaccuracies of gas measurements, furnish an explanation of the reason for the adjustment, the Mcf and dollar amount of adjustment and account charged or credited.

4. Give a concise statement of the facts and the accounting performed with respect to any encroachment of withdrawals during the year, or restoration of previous encroachment, upon native gas constituting the "gas cushion" of any storage reservoir.

5. If the respondent uses a "base stock" in connection with its inventory accounting, give a concise statement of the basis of establishing such "base stock" and the inventory basis and the accounting performed with respect to any encroachment of withdrawals upon "base stock", or restoration of previous encroachment, including brief particulars of any such accounting during the year.

6. If respondent has provided accumulated provision for stored gas which may not eventually be fully recovered from any storage project furnish a statement showing: (a) date of Commission authorization of such accumulated provision (b) explanation of circumstances requiring such provision (c) basis of provision and factors of calculation (d) estimated ultimate accumulated provision accumulation (e) a summary showing balance of accumulated provision and entries during year.

7. Pressure base of gas volumes reported in this schedule is 14.73 psia at 60° F.

Line No.	Description (a)	Non Current (Account 117) (b)	Current (Account 164.1) (c)	LNG (Account 164.1) (d)	LNG (Account 164.2) (e)	Total (i)
1	Balance at Beginning of Year					
2	Gas Delivered to Storage					
3	Contra Account					
4	Gas Withdrawn from Storage					
5	Contra Account	SEE FERC ANNUAL REPORT				
6	Other Debits and Credits	PAGE 220				
7	(Explain					
8	Balance at End of Year					
9	Dekatherms					
10	Amount Per Dekatherm					
11						
12	Balance at End of Year					
13	MCF					
14	Amount per Mcf					

15 State basis of segregation of inventory between current and noncurrent portions.
16

17 Gas delivered to storage:
18 Mcf
19 Amount per Mcf
20 Cost basis of gas delivered to storage:
21 Specify: Own production (give production area, see
22 uniform system of accounts); average system purchases
23 specific purchases (state which purchases).
24 Does cost of gas delivered to storage include any expenses
25 for use of respondent's transmission, storage, or other
26 facilities? If so, give particulars and date of Commission
27 approval of the accounting.
28

29 Gas withdrawn from storage:
30 Mcf
31 Amount per Mcf
32 Cost basis of withdrawals:
33 Specify: average cost, lifo, fifo. (Explain any change in
34 inventory basis during year and give date of Commission;
35 approval of the change or approval of an inventory basis
36 different from that referred to in uniform system of accounts)

STATE OF OREGON - GAS PURCHASES (Accounts 800, 801, 802, 803, 804.1 and 805)

1. Report particulars of gas purchases during the year in the manner prescribed below. (Code numbers to be used in reporting for Columns (d), (e) and (f) will be supplied by the Commission.)

2. Provide subheadings and totals for prescribed accounts as follows

800 Natural Gas Well Head Purchases

801 Natural Gas Field Line Purchases

802 Natural Gas Gasoline Plant Outlet Purchases

803 Natural gas Transmission Line Purchases

804 Natural Gas City Gate Purchases

804.1 Liquefied natural Gas Purchases

805 Other gas Purchases

Purchases are to be reported in account number sequence, e.g. all purchases charged to Account 800, followed by charges to Account 801, etc. Under each account number,purchases should be reported by states in alphabetical order.Totals are to be shown for each account in Columns (k) and (l)and should agree with the books of accounts, or any differences reconciled.

3. Purchases may be reported by gas purchase contract totals (at the option of the respondent) where one contract includes two or more FERC producer rate schedules or small producer certificates, provided that the same price is being paid for all gas purchased under the contract. If two or more prices are in effect under the same contract, separate details for each price shall be reported. The name, and FERC rate schedule or small producer certificate docket number of each seller included in the contract total shall be listed on separate sheets, clearly cross-referenced. Where two or more prices are in effect, the sellers at each price are to be listed separately.

4. Purchases of less than 100,000 MCF per year per contract from sellers not affiliated with the reporting company may (at the option of the respondent) be grouped by account number, except when the purchases were permanently discontinued during the reporting year. When grouped purchases are reported, the number of grouped purchases is to be reported in Column (a). Only Columns (a), (k), (l), and (m) are to be completed for grouped purchases; however, the Commission may request additional details when necessary. Grouped non-jurisdictional purchases should be shown on a separate line.

5. Column instructions are as follows:

Columns (a) and (d) - In reporting the names of sellers under FERC rate schedules, use the names as they appear on the filed rate schedules. Abbreviations may be used where necessary. The code number to be used is the Commission assigned number.

Column (b) - Give the name of the producing field only for purchases at the wellhead or from field lines. The plant name should be given for purchases from gasoline plant outlets. If purchases under a contract are from more than one field or plant, use the name of the one contributing the largest volume.Use a footnote to list the other fields or plants involved.

Column (c) - State the net rate in cents per MCF as of December 31 for the reported year, applicable to the volume shown in Column (k). The net rate includes all applicable deductions and downward adjustments. The rate is effective if filed pursuant to applicable statues and regulations and (as to FERC rates schedules) permitted by the commission to become effective.

Columns (e) and (f) - General Services Administration location code designations are to be used to designate the state and county where the gas is received.Where gas is received in more than one county, use the code designation for the county having the largest volume,and by footnote list the other countries involved.

Column (g) - List the assigned commission rate schedule number or small producer certificate docket number. Use the designation "NF" in Column (g) to indicate non-jurisdictional purchases.

Column (h) - In some cases, two or more lines will be required to report a purchase, as when two or more rates are being paid under the same contract, or when purchases under the same rate schedule are charged to more than one account. If for such reasons the producer rate schedule or non-jurisdictional purchase contract appears on more than one line, enter a numerical code (selected by the respondent) in Column (h) to so indicate. Once established,the same numerical suffix is to be used for all subsequent-year reporting of the purchase. If the purchase was permanently discontinued during the reporting year, so indicate by an asterisk (*) in column (h). Column (h) is to be used also, to enter any Commission assigned letter rate schedule suffix (e.g. R.S. No. 22A).

Column (i) - Show date of the gas purchase contract. If gas is purchased under a renegotiated contract show the dates of the original and renegotiated contracts on the following line in brackets. If new acreage is dedicated by ratification of an existing contract, show the date of the ratification, rather than the date of the original contract. Ifgas is being sold from a different reservoir than the original dedicated acreage pursuant to Section 2.56 (f) (2) of the Commission's Rules of Practice and Procedure, place the letter "A" after the contract date.

Column (j) - Show, for each purchase, the approximate BTU per cubic foot, determined in accordance with the definition in item No. 7 of the General Instructions for FERC Form 2.

Column (k) - State the volume of purchased gas as finally measured for purpose of determining the amount payable for the gas. Include current year receipts of make-up gas that was paid for in prior years.

Column (l) - State the dollar amount (omit cents)paid and previously paid for the volumes of gas shown in Column (k).

Column (m) - State the average cost per MCF to the nearest hundredth of a cent. (Column (l) divided by Column (k) multiplied by 100).

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Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

STATE OF OREGON - GAS PURCHASES (Account 800, 801, 802, 803, 804, 804.1 and 805) (Con't)

Line No.	NAME OF SELLER (DESIGNATE ASSOCIATED COMPANIES) (a)	NAME OF PRODUCING FIELD OR GASOLINE PLANT (b)	NET RATE EFFECTIVE DECMEBER 31 (c)
1			
2			
3			
4			
5			
6		**SEE FERC ANNUAL REPORT**	
7		**PAGE 520**	
8			
9			
10			
11			
12			
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26			
27			
28			
29			
30			

Name of Respondent	This Report is:	Date of Report	Year of Report
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Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

Line	SELLAR CODE	STATE CODE	COUNTRY CODE	RATE SCHEDULE		DATE OF CONTRACT	APPROX BTU PER CU FEET	GAS PURCHASED - MCF (14.73	COST OF GAS	COST PER MCF (CENTS)
				No.	Suffix					
No.	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1										
2										
3										
4										
5										
6										
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26										
27										
28										
29										
30										

SEE FERC ANNUAL REPORT PAGE 520

Name of Respondent	This Report is:	Date of Report	Year of Report
	(1) ☒ An Original	(Mo, Da, Yr)	
Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

STATE OF OREGON - GAS USED IN UTILITY OPERATIONS - CREDIT (Accounts 810, 811 and 812)

1. Report below particulars of credits during the year to Accounts 810, 811 and 812, which offset charges to operating expenses or other accounts for the cost of gas from the respondent's own supply.
2. Natural gas means either natural gas unmixed, or any mixture of natural and manufactured gas.
3. If the reported MCF for any use is an estimated quantity, state such fact.
4. If any natural gas was used by the respondent for which charge was not made to the appropriate operating expenses or other account, list separately in column (c) the MCF of gas so used, omitting entries in columns (d) and (e).
5. Pressure base of measurement, to be reported in columns (c) and (f) is 14.73 psia at 60° F.

Line No.	PURPOSE FOR WHICH GAS WAS USED (a)	ACCOUNT CHARGED (b)	NATURAL GAS: Dth OF GAS USED (14.73 PSIA AT 60° F) (c)	NATURAL GAS: AMOUNT OF CREDIT (d)	NATURAL GAS: AMOUNT PER Dth (CENTS) (e)	MANUFACTURED GAS: MCF OF GAS USED (14.73 PSIA AT 60° F) (f)	MANUFACTURED GAS: AMOUNT OF CREDIT (g)
1	810 Gas used for Compressor Station Fuel - Credit		—	—	—	N/A	N/A
2	811 Gas used for Products Extraction - Credit		—	—	—	N/A	N/A
3	(a) Gas shrinkage & other usage in respondent's own processing		—	—		N/A	N/A
4	(b) Gas shrinkage, etc. for respondent's gas processed by others		—	—		N/A	N/A
5	812 Gas used for Other Utility Operations - Credit		420,036	221,845	0.53	N/A	N/A
6	(Report separately for each principal use, Group minor uses.)					N/A	N/A
7	System - All Districts		134,476	221,845			
8	LNG Plants		110,203	0*			
9	Underground Storage Compressors		175,357	0*			
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25	TOTAL		420,036	221,845	0.53		

* Included in the Cost of Inventory

Name of Respondent	This Report is:	Date of Report	Year of Report
	(1) ☒ An Original	(Mo, Da, Yr)	
Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

STATE OF OREGON - GAS ACCOUNT - NATURAL GAS

1. The purpose of this schedule is to account for the quantity of natural gas received and delivered by the respondent, taking into consideration differences in pressure bases used in measuring Mcf of natural gas received and delivered.

2. Natural gas means either natural gas unmixed or any mixture of natural and manufactured gas.

3. Enter in column (c) the Dth as reported in the schedules indicated for the items of receipts and deliveries.

4. In a footnote report the volumes of gas from respondent's own production delivered to respondent's transmission system and included in natural gas sales.

5. If the respondent operates two or more systems which are not interconnected, separate schedules should be submitted. Insert pages for this purpose.

Line No.	ITEM (a)	REF. PAGE NO. (b)	Amount of Dth (c)
1	**GAS RECEIVED**		
2	Natural Gas Produced		—
3	LPG Gas Produced and Mixed with Natural Gas		—
4	Manufactured Gas Produced and Mixed with Natural Gas		—
5	Purchased Gas		
6	(a.) Wellhead		—
7	(b.) Field Lines		468,836
8	(c.) Gasoline Plants		—
9	(d.) Transmission Line		—
10	(e.) City Gate Under FERC Rate Schedules		76,956,797
11	(f.) LNG		—
12	(g.) Other		—
13	TOTAL, Gas Purchased (Enter Total of lines 7 thru 13)		77,425,633
14	Gas of Others Received for Transportation		38,824,657
15	Receipts of Respondents' Gas Transported or Compressed by Others		—
16	Exchange Gas Received		—
17	Gas Withdrawn from Underground Storage	*	3,725,443
18	Gas Received from LNG Storage		406,453
19	Gas Received from LNG Processing		—
20	Other Receipts (Specify): Off System Storage Withdrawal		1,883,522
21	TOTAL Receipts (Enter Total of lines 2 thru 5, 13, and 14 thru 20)		122,265,708

* This amount does not tie to system page 512 as it only includes Oregon storage sites.

Name of Respondent	This Report is:	Date of Report	Year of Report
	(1) ☒ An Original	(Mo, Da, Yr)	
Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

STATE OF OREGON - GAS ACCOUNT - NATURAL GAS (CONT'D)

Line No.	ITEM (a)	REF. PAGE NO. (b)	Amount of Dth (c)
	GAS DELIVERED		
22	Natural Gas Sales		
23	a. Field Sales		
24	(i) To Interstate Pipeline Companies for Resale pursuant to		—
25	FERC Rate Schedules		—
26	(ii) Retail Industrial Sales		—
27	(iii) Other Field Sales		—
28	TOTAL, Field Sales		—
29	b. Transmission System Sales		
30	(i) To Interstate Pipeline Co. for Resale Under FERC Rate Schedules		—
31	(ii) To Interstate Pipeline Co. and Gas Utilities for resale under		—
32	FERC Rate Schedules		—
33	(iii) Mainline Industrial Sales Under FERC Certification		—
34	(iv) Other Mainline Industrial Sales		—
35	(v) Other Transmission System Sales		—
36	TOTAL, Transmission System Sales		—
37	c. Local Distribution by Respondent		
38	(i) Retail Industrial Sales		8,610,626
39	(ii) Other Distribution System Sales		66,369,467
40	TOTAL, Distribution System Sales		74,980,093
41	d. Interdepartmental sales		—
42	e. Unbilled Therms		(76,987)
43	TOTAL SALES		74,903,106
44	Deliveries of Gas Transported or Compressed for:		
45	(a.) Other Interstate Pipeline Companies		—
46	(b.) Others - Transportation		38,824,657
47	TOTAL, Gas Transported or Compressed for Others		38,824,657
48	Deliveries of Respondent's Gas for Trans. or Compression by Others		—
49	Exchange Gas Delivered		—
50	Natural Gas Used by Respondent		420,036
51	Natural Gas Delivered to Underground Storage	*	5,311,044
52	Natural Gas Delivered to LNG Storage		664,753
53	Natural Gas Delivered to LNG Processing	331	—
54	Natural Gas for Franchise Requirements		—
55	Other Deliveries (Specify): FIK		—
56	TOTAL SALES & OTHER DELIVERIES		120,123,596
	UNACCOUNTED FOR GAS		
57	Production System Losses		—
58	Storage Losses: Mist Gas Loss		—
59	Transmission System Losses		—
60	Distribution System Losses		2,142,112
61	Other Losses (Leakage)		—
62	TOTAL Unaccounted for		2,142,112
63	TOTAL SALES, OTHER DELIVERIES, AND UNACCOUNTED FOR		122,265,708

* This amount does not tie to system page 512 as it only includes Oregon storage sites.

Name of Respondent	This Report is:	Date of Report	Year of Report
	(1) ☒ An Original	(Mo, Da, Yr)	
Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

STATE OF OREGON - MISCELLANEOUS GENERAL EXPENSES (Account 930.2)

Report below the information called for concerning items included in miscellaneous general expenses.

Line No.	ITEMS (a)	TOTAL (b)	AMOUNT APPLICABLE TO STATE OF OREGON (c)	AMOUNT APPLICABLE TO OTHER STATES (d)
	SEE FERC ANNUAL REPORT PAGE 335			

Name of Respondent	This Report is:	Date of Report	Year of Report
	(1) ☒ An Original	(Mo, Da, Yr)	
Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

STATE OF OREGON - POLITICAL ADVERTISING

1. List all payments for advertising, the purpose of which is to aid or defeat any measure before the people or to promote or prevent the enactment of any national, state, district or municipal legislation.
2. Give the specific purpose of such advertising, when and where placed, and the account or accounts charged.
3. Report whole dollars only. Provide a total for each account and a grand total.

Line No.	DESCRIPTION (a)	ACCOUNT CHARGED (b)	AMOUNT (d)
	NONE		

Name of Respondent	This Report is:	Date of Report	Year of Report
	(1) ☒ An Original	(Mo, Da, Yr)	
Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

STATE OF OREGON - POLITICAL CONTRIBUTIONS

1. List all payments for advertising, the purpose of which is to aid or defeat any measure before the people or to promote or prevent the enactment of any national, state, district or municipal legislation.

2. The purpose of all contributions or payments should be clearly explained

3. Report whole dollars only. Provide a total for each account and a grand total.

Line No.	DESCRIPTION (a)	ACCOUNT CHARGED (b)	AMOUNT (c)
1	INTERNAL LOBBY AND INTERNAL RESOURCES	426-04935	23,251
2	GROW OREGON	426-04935	12,500
3	PORTLANDERS FOR SAFETY & HEALTH	426-04935	12,500
4	OREGON BUSINESS & INDUSTRY	426-04935	10,000
5	OREGONIANS FOR BALANCED CLIMATE POLICY	426-04935	5,000
6	PORTLAND BUSINESS ALLIANCE	426-04935	2,500
7	KEEP LAKE OSWEGO SCHOOLS FIRST	426-04935	1,000
8	PCC FORWARD	426-04935	1,000
9	YES FOR HILLSBORO SCHOOLS	426-04935	1,000
10	OTHER < $1,000	426-04935	6,784
11	Total 426-04935	Total	75,535
12			
13	NATURAL GAS POLITICAL COMMITTEE	426-04955	130,000
14	Total 426-04955	Total	130,000
15			
16			
17	INTERNAL LOBBY AND INTERNAL RESOURCES	426-04950	271,283
18	Total 426-04950	Total	271,283
19			
20			
21			
22			
23		Total	476,818
24			
25			
26			
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28			
29			
30			

Name of Respondent	This Report is:	Date of Report	Year of Report
	(1) ☒ An Original	(Mo, Da, Yr)	
Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

STATE OF OREGON - EXPENDITURES TO ANY PERSON OR ORGANIZATION HAVING AN AFFILIATED INTEREST FOR SERVICES, ETC.

1. Report all expenditures to any person or organization having an affiliated interest for service, advice, auditing, associating, sponsoring, engineering, managing, operating, financial, legal or other services. See Oregon Revised Statute 757.015 for definition of "affiliated interest."

2. Give reference if such expenditures have in the past been approved by the Commission. Describe the services received and the account or accounts charged. Report whole dollars only.

Line No.	DESCRIPTION (a)	ACCOUNT NUMBER (b)	TOTAL AMOUNT (d)	AMOUNT ASSIGNED TO OREGON (d)
1	The required affiliated interest expenditure information for 2017 will be provided in NW Natural's FY 2017 annual Affiliated Interest Report.			
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Name of Respondent	This Report is:	Date of Report	Year of Report
	(1) ☒ An Original	(Mo, Da, Yr)	
Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

STATE OF OREGON - DONATIONS AND MEMBERSHIPS

1. List all donations and membership expenditures made by the utility during the year and the accounts charged. Give the name, city, and state of each organization to whom a donation has been made. Group donations under headings such as:

a. Contributions to and memberships in charitable organizations.

b. Organizations of the utility industry.

c. Technical and professional organizations.

d. Commercial and trade organizations.

e. All other organizations and kinds of donations and contributions.

2. List donations by type and group by the accounts charged. Report whole dollars only. Provide a total for each group of donations.

Line No.	DESCRIPTION (a)	ACCOUNT NUMBER (b)	TOTAL AMOUNT (c)	AMOUNT ASSIGNED TO OREGON (d)
1	All donations listed below are contributions to charitable organizations.			
2	UNITED WAY	426-02180	120,500	100,000
3	OREGON COMMUNITY FOUNDATION	426-02180	63,940	46,302
4	CASA FOR CHILDREN	426-02180	42,625	42,625
5	AMERICAN RED CROSS CASCADES REGION	426-02180	37,581	27,581
6	BRIDGE MEADOWS	426-02180	36,000	36,000
7	JANUS YOUTH PROGRAMS	426-02180	35,715	30,000
8	SOLVE	426-02180	35,000	35,000
9	REGIONAL ARTS & CULTURE COUNCIL	426-02180	23,780	23,780
10	HABITAT FOR HUMANITY	426-02180	20,447	18,447
11	PORTLAND CLASSICAL CHINESE GARDEN	426-02180	15,300	15,300
12	MERCY CORPS	426-02180	15,000	15,000
13	UNIVERSITY OF OREGON FOUNDATION	426-02180	13,500	13,500
14	LIFEWORKS NORTHWEST	426-02180	13,380	13,380
15	PORTLAND CENTER STAGE	426-02180	12,500	12,500
16	ENVIRONMENTAL FEDERATION OF OREGON	426-02180	12,000	12,000
17	OREGON ALLIANCE OF INDEPENDENT	426-02180	12,000	12,000
18	OREGON STATE UNIVERSITY	426-02180	10,800	10,800
19	BLACK UNITED FUND OF OREGON	426-02180	10,500	10,500
20	LITERARY ARTS INC	426-02180	10,500	10,500
21	FRIENDS OF THE CHILDREN - PORTLAND	426-02180	10,000	8,000
22	OREGON HISTORICAL SOCIETY	426-02180	10,000	10,000
23	OREGON SYMPHONY ASSOCIATION	426-02180	10,000	10,000
24	VIRGINIA GARCIA MEMORIAL FOUNDATION	426-02180	10,000	10,000
25	SMART	426-02180	8,200	8,200
26	FOREST PARK CONSERVANCY	426-02180	8,200	8,200
27	OREGON FOOD BANK INC	426-02180	7,534	7,534
28	FRIENDS OF TREES	426-02180	7,500	5,000
29	BOYS & GIRLS CLUB OF SALEM, MARION	426-02180	7,500	7,500
30	THE FRESHWATER TRUST	426-02180	7,100	7,100
31	THE NATURE CONSERVANCY	426-02180	7,035	7,035
32	CENTRAL CITY CONCERN INC	426-02180	6,500	6,500
33	DOERNBECHER CHILDREN'S	426-02180	6,200	6,200
34	PORTLAND ART MUSEUM	426-02180	6,000	6,000
35	JUNIOR ACHIEVEMENT	426-02180	5,800	5,800
36	GUIDE DOGS FOR THE BLIND INC	426-02180	5,700	5,700
37	CASH OREGON	426-02180	5,400	5,400
38	COMMUNITY WAREHOUSE	426-02180	5,400	5,400
39	COMMUNITY TRANSITIONAL SCHOOL	426-02180	5,300	5,300
40	ETHOS INC	426-02180	5,300	5,300
41	COLUMBIA SPRINGS	426-02180	5,000	—

42	I HAVE A DREAM FOUNDATION OREGON	426-02180	5,000	5,000
43	IMPACT NW	426-02180	5,000	5,000
44	JAPANESE GARDEN	426-02180	5,000	5,000
45	NORTHWEST EARTH INSTITUTE	426-02180	5,000	5,000
46	OREGON MUSEUM OF SCIENCE & INDUSTRY	426-02180	5,000	5,000
47	P:EAR	426-02180	5,000	5,000
48	PORTLAND OPERA ASSOCIATION INC	426-02180	5,000	5,000
49	PORTLAND PARKS FOUNDATION	426-02180	5,000	5,000
50	SCHOOLHOUSE SUPPLIES INC	426-02180	5,000	5,000
51	THE CHILDREN'S CENTER OF CLACKAMAS	426-02180	5,000	5,000
52	THE LIBRARY FOUNDATION	426-02180	5,000	5,000
53	TRANSITION PROJECTS INC	426-02180	5,000	5,000
54	METROPOLITAN FAMILY SERVICE	426-02180	5,000	5,000
55	NEW AVENUES FOR YOUTH	426-02180	5,000	5,000
56	NEIGHBORHOOD PARTNERSHIPS INC	426-02180	5,000	5,000
57	CLARK COUNTY VOCATIONAL SKILLS CENTER	426-02180	5,000	—
58	BLACK PARENT INITIATIVE	426-02180	5,000	5,000
59	KIDS INTERVENTION & DIAGNOSTIC SVC	426-02180	5,000	5,000
60	YWCA OF GREATER PORTLAND	426-02180	5,000	5,000
61	OREGON STATE PARKS TRUST	426-02180	5,000	5,000
62	ALL HANDS RAISED	426-02180	5,000	5,000
63	KAIROSPDX	426-02180	4,000	4,000
64	TUALATIN RIVERKEEPERS	426-02180	4,000	4,000
65	EPISCOPAL LAYMAN'S MISSION SOCIETY	426-02180	4,000	4,000
66	BEAVERTON EDUCATION FOUNDATION	426-02180	4,000	4,000
67	BOYS & GIRLS CLUBS	426-02180	3,500	3,500
68	PROVIDENCE CHILD CENTER FOUNDATION	426-02180	3,500	3,500
69	CLACKAMAS WOMEN'S SERVICES	426-02180	3,000	3,000
70	FRIENDS OF THE RIDGEFIELD NATIONAL WILDLIFE REFUGE	426-02180	3,000	—
71	JOIN	426-02180	3,000	3,000
72	LATINO NETWORK	426-02180	3,000	3,000
73	LOWER COLUMBIA RIVER ESTUARY PARTNERSHIP	426-02180	3,000	1,500
74	PORTLAND CHILDREN'S MUSEUM	426-02180	3,000	3,000
75	PORTLAND FESTIVAL SYMPHONY	426-02180	3,000	3,000
76	HARPER'S PLAYGROUND	426-02180	2,900	2,900
77	WIND & OAR BOAT SCHOOL	426-02180	2,850	2,850
78	CHESS FOR SUCCESS	426-02180	2,800	2,800
79	OREGON HUMANE SOCIETY	426-02180	2,694	2,694
80	NATIVE AMERICAN YOUTH ASSOCIATION	426-02180	2,500	2,500
81	BASIC RIGHTS EDUCATION FUND	426-02180	2,500	2,500
82	CAMPBELL INSTITUTE	426-02180	2,500	2,500
83	CASA OF LINCOLN COUNTY	426-02180	2,500	2,500
84	COLUMBIA RIVER MARITIME MUSEUM	426-02180	2,500	2,500
85	COMMUNITY ACTION ORGANIZATION	426-02180	2,500	2,500
86	DRESS FOR SUCCESS OF OREGON INC	426-02180	2,500	2,500
87	GROWING GARDENS	426-02180	2,500	2,500
88	MACDONALD CENTER	426-02180	2,500	2,500
89	MT HOOD COMMUNITY COLLEGE FOUNDATION	426-02180	2,500	2,500
90	MUSLIM EDUCATIONAL TRUST	426-02180	2,500	2,500
91	NORTHWEST NATURAL GAS CO	426-02180	2,500	2,500
92	READING RESULTS	426-02180	2,500	2,500
93	SATURDAY ACADEMY	426-02180	2,500	2,500

94	STAND FOR CHILDREN	426-02180	2,500	2,500
95	THE DOUGY CENTER INC	426-02180	2,500	2,500
96	OREGON ENVIRONMENTAL COUNCIL	426-02180	2,500	2,500
97	THE WALLACE MEDICAL CONCERN	426-02180	2,500	2,500
98	THE OREGON PARTNERSHIP INC	426-02180	2,500	2,500
99	COALITION OF COMMUNITIES OF COLOR	426-02180	2,500	2,500
100	OPEN SCHOOL INC	426-02180	2,500	2,500
101	VOLUNTEERS OF AMERICA OREGON	426-02180	2,500	2,500
102	FREE CLINIC OF SOUTHWEST WASHINGTON	426-02180	2,500	—
103	PLANNED PARENTHOOD	426-02180	2,300	2,300
104	HISPANIC METROPOLITAN CHAMBER	426-02180	2,000	2,000
105	NEIGHBORHOOD HOUSE	426-02180	2,000	2,000
106	NORTHWEST HOUSING ALTERNATIVES	426-02180	2,000	2,000
107	SOUTH LANE FAMILY RELIEF NURSERY	426-02180	2,000	2,000
108	THE CHILDREN'S BOOK BANK	426-02180	2,000	2,000
109	RAPHAEL HOUSE OF PORTLAND	426-02180	2,000	2,000
110	OREGON COUNCIL FOR THE HUMANITIES	426-02180	2,000	2,000
111	BOYS & GIRLS CLUB OF SOUTHWESTERN	426-02180	2,000	2,000
112	BOYS & GIRLS CLUB OF ALBANY	426-02180	1,800	1,800
113	BOYS & GIRLS CLUB OF CORVALLIS	426-02180	1,800	1,800
114	BOYS & GIRLS CLUBS OF SW WASHINGTON	426-02180	1,800	—
115	BOYS & GIRLS CLUBS OF EMERALD VALLEY	426-02180	1,800	1,800
116	CATHOLIC CHARITIES	426-02180	1,750	1,750
117	PORTLAND RESCUE MISSION	426-02180	1,708	1,708
118	ASSISTANCE LEAGUE OF GREATER PORTLAND	426-02180	1,500	1,500
119	SERENDIPITY CENTER INC	426-02180	1,500	1,500
120	SHARE INC	426-02180	1,500	—
121	STORE TO DOOR	426-02180	1,500	1,500
122	UNITED WAY OF LINN COUNTY	426-02180	1,500	1,500
123	WILLAMETTE PARTNERSHIP	426-02180	1,500	1,500
124	PORTLAND FRUIT TREE PROJECT	426-02180	1,500	1,500
125	OPAL CREEK ANCIENT FOREST CENTER	426-02180	1,500	1,500
126	CHILDREN'S TRUST FUND	426-02180	1,346	1,346
127	CASA OF LINN COUNTY INC	426-02180	1,000	1,000
128	FENCES FOR FIDO	426-02180	1,000	1,000
129	FOOD FOR LANE COUNTY	426-02180	1,000	1,000
130	FOOD SHARE OF LINCOLN COUNTY	426-02180	1,000	1,000
131	FORT VANCOUVER NATIONAL TRUST	426-02180	1,000	—
132	FRIENDLY HOUSE INC	426-02180	1,000	1,000
133	LINN COUNTY CHILD VICTIM ASSESSMENT CENTER	426-02180	1,000	1,000
134	NORTHWEST FAMILY SERVICES	426-02180	1,000	1,000
135	UNITED WAY OF CLATSOP COUNTY	426-02180	1,000	1,000
136	UNITED WAY OF LANE COUNTY	426-02180	1,000	1,000
137	UNITED WAY OF SOUTHWESTERN OREGON	426-02180	1,000	1,000
138	UNITED WAY OF THE COLUMBIA GORGE	426-02180	1,000	1,000
139	OLD MILL CENTER FOR CHILDREN & FAMILY	426-02180	1,000	1,000
140	SOUTHWESTERN OREGON COMMUNITY COLLEGE FOUNDATION	426-02180	1,000	1,000
141	DAVID DOUGLAS EDUCATIONAL FOUNDATION	426-02180	1,000	1,000
142	ASIAN AMERICAN YOUTH LEADERSHIP CONFERENCE	426-02180	1,000	1,000
143	SUSTAINABLE NORTHWEST	426-02180	1,000	1,000
144	PORTLAND OPPORTUNITIES INDUSTRIALIZATION CENTER	426-02180	1,000	1,000
145	ALLEN TEMPLE COMMUNITY MINISTRIES	426-02180	1,000	1,000

146	NEIGHBORS FOR KIDS	426-02180	1,000	1,000
147	NORTHWEST ASSOCIATION FOR BLIND ATHLETES	426-02180	1,000	—
148	DONATIONS <$1K	426-02180	30,037	29,412
149				
150	TOTAL DONATIONS		1,001,822	918,544

Name of Respondent	This Report is:	Date of Report	Year of Report
	(1) ☒ An Original	(Mo, Da, Yr)	
Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

State of Oregon - Officers' Salaries

1. Report below the name, title and salary for each executive officer whose salary is $50,000 or more. An "executive officer" of a respondent includes its president, secretary, treasurer, and vice president in charge of a principal business unit, division or function (such as sales, administration, or finance), and any other person who performs similar policy-making functions.

2. If a change was made during the year in the incumbent of any position, show name and total remuneration of the previous incumbent and date change in incumbency was made.

3. Utilities which are required to file similar data with the Securities and Exchange Commission, may substitute a copy of Item 4, Regulation S-K, identified as this schedule page. The substituted page(s) should be conformed to the size of this page.

Line No.	Title (a)	Name of Officer (b)	SALARY FOR YEAR Total[1] (c)	SALARY FOR YEAR OREGON (d)
1	Chief Executive Officer and President	David H. Anderson	641,667	641,667
2	Senior Vice President and Chief Financial Officer	Frank H. Burkhartsmeyer[2]	248,611	248,611
3	Vice President, Chief Accounting Officer, Controller and Treasurer	Brody J. Wilson[2]	272,028	272,028
4	Senior Vice President and Chief Administrative Officer	Lea Anne Doolittle	299,500	299,500
5	Vice President and Chief Information Officer	James R. Downing	80,208	80,208
6	Vice President, Communications and Chief Marketing Officer	Kimberly A. Heiting[3][4]	246,667	246,667
7	Senior Vice President, Regulation and General Counsel	MardiLyn Saathoff	355,167	355,167
8	Senior Vice President, Utility Operations	Grant M. Yoshihara[4]	299,500	299,500
9	Vice President, Chief Compliance Officer and Corporate Secretary	Shawn M. Filippi	235,833	235,833
10	Vice President of Public Affairs	Thomas J. Imeson	257,667	257,667
11	Vice President, Strategy and Business Development	Justin Palfreyman	270,833	270,833
12	Vice President, Utility Services	Lori Russell	210,833	210,833
13	President and Chief Executive Officer, NW Natural Gas Storage, LLC	David A. Weber	279,325	279,325

(1) Salary amounts do not include bonuses paid to executives.

(2) Frank H. Burkhartsmeyer was appointed Senior Vice President and Chief Financial Office effective May 17, 2017, replacing Brody J. Wilson, who had been serving as Chief Financial Office on an interim basis. Effective May 17, 2017, Mr. Wilson was appointed Vice President, Chief Accounting Officer, Controller, and Treasurer.

(3) Kimberly A. Heiting was appointed Senior Vice President, Communications and Chief Marketing Officer effective January 1, 2018.

(4) Grant M. Yoshihara announced his intention to retire effective March 31, 2018. The Board of Directors appointed Kimberly A. Heiting as Senior Vice President, Operations and Chief Marketing Officer and Jon Huddleston Vice President, Engineering and Utility Operations, effective March 31, 2018.

Name of Respondent	This Report is:	Date of Report	Year of Report
	(1) ☒ An Original	(Mo, Da, Yr)	
Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

STATE OF OREGON - DONATIONS OR PAYMENTS FOR SERVICES RENDERED BY PERSONS OTHER THAN EMPLOYEES AND CHARGED TO OREGON OPERATING ACCOUNTS

1. Report for each service rendered (including materials furnished incidental to the service which are impracticable of (separation)by recipient and in total the aggregate of all payments made during the year where the aggregate of such payments to a recipient was $25,000 or more including fees, retainers, commissions, gifts, contributions, assessments, bonuses, subscriptions, allowances for expenses or any other form of payments for services, traffic settlements, amounts paid for construction or maintenance of plant to persons other than affiliates to any one corporation, institution, association, firm partnership, committee, or person (not an employee of the respondent). Indicate by an asterisk in column (c) each item that includes payments for materials furnished incidental to the services performed. Payments to a recipient by two or more companies within a single system under a cost sharing or other joint arrangement shall be considered a single item for reporting in this schedule and shall be shown in the report of the principal company in the joint arrangement(as measured by gross operating revenues) with references thereto in the reports of the other system companies in the joint arrangement.

2. If more convenient, this schedule may be filled out for a group of companies considered as one system and shown only in the report of the principal company in the system, with references thereto in the reports of the other companies.

Line No.	NAME OF RECIPENT (a)	NATURE OF SERVICE (b)	AMOUNT OF PAYMENT (c)
	SEE FERC ANNUAL REPORT PAGE 357		

Name of Respondent	This Report is:	Date of Report	Year of Report
	(1) ☒ An Original	(Mo, Da, Yr)	
Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

In order to help us with production of our Oregon Utility Statistics publication, please indicate:

Oregon Production Statistics (Therms)		—
Gas Produced		753,331,160
Gas Purchased		753,331,160
Total Receipts		
Gas Sales		749,800,930
Gas Used by Company		4,200,360
Gas Delivered to LNG and Storage - Net		(396,210)
Losses & billing Delay		(273,920)
Total Disbursements		753,331,160
Oregon Revenue by Service Class		
Residential	$	407,198,747
Commercial & Industrial		
Firm		230,735,208
Interruptible		21,554,862
Transportation		17,987,262
Total	$	677,476,079
Gas Sold in Therms (Oregon)		
Residential		410,861,997
Commercial & Industrial		
Firm		284,460,254
Interruptible		53,708,806
Transportation		388,246,568
Total		1,137,277,625
Average Number of Oregon Customers		
Residential		588,986
Commercial & Industrial		
Firm		61,291
Interruptible		125
Transportation		351
Total		650,753

Name of Respondent	This Report is:	Date of Report	Year of Report
Northwest Natural Gas Company	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	December 31, 2017

Distribution of Salaries and Wages
Oregon Jurisdiction

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals 'and Other Accounts, and enter such amounts in the appropriate lines and columns provided. Salaries and wages billed to the Respondent by an affiliated company must be assigned to the particular operating function(s) relating to the expenses.

In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used. When 'reporting detail of other accounts, enter as many rows as necessary numbered sequentially starting with 75.01, 75.02, etc.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Payroll Billed by Affiliated Companies (c)	Allocation of Payroll Charged for Clearing Accounts (d)	Total (e)
1	Electric				
2	Operation				
3	Production				
4	Transmission				
5	Distribution	SEE FERC ANNUAL REPORT			
6	Customer Accounts	PAGES 354-355			
7	Customer Service and Informational				
8	Sales				
9	Administrative and General				
10	TOTAL Operation (Total of lines 3 thru 9)				
11	Maintenance				
12	Production				
13	Transmission				
14	Distribution				
15	Administrative and General				
16	TOTAL Maintenance (Total of lines 12 thru 15)				
17	Total Operation and Maintenance				
18	Production (Total of lines 3 and 12)				
19	Transmission (Total of lines 4 and 13)				
20	Distribution (Total of lines 5 and 14)				
21	Customer Accounts (line 6)				
22	Customer Service and Informational (line 7)				
23	Sales (line 8)				
24	Administrative and General (Total of lines 9 and 15)				
25	TOTAL Operation and Maintenance (Total of lines 18 thru 24)				
26	Gas				
27	Operation				
28	Production - Manufactured Gas				
29	Production - Natural Gas(Including Exploration and Development)				
30	Other Gas Supply				
31	Storage, LNG Terminaling and Processing				
32	Transmission				
33	Distribution				
34	Customer Accounts				
35	Customer Service and Informational				
36	Sales				
37	Administrative and General				
38	TOTAL Operation (Total of lines 28 thru 37)				
39	Maintenance				
40	Production - Manufactured Gas				

41	Production - Natural Gas(Including Exploration and Development)				
42	Other Gas Supply				
43	Storage, LNG Terminaling and Processing				
44	Transmission				
45	Distribution				
46	Administrative and General				
47	TOTAL Maintenance (Total of lines 40 thru 46)				
48	Gas (Continued)				
49	Total Operation and Maintenance				
50	Production - Manufactured Gas (Total of lines 28 and 40)				
51	Production - Natural Gas (Including Expl. and Dev.) (ll. 29 and 41)	**SEE FERC ANNUAL REPORT**			
52	Other Gas Supply (Total of lines 30 and 42)	**PAGES 354-355**			
53	Storage, LNG Terminaling and Processing (Total of ll. 31 and 43)				
54	Transmission (Total of lines 32 and 44)				
55	Distribution (Total of lines 33 and 45)				
56	Customer Accounts (Total of line 34)				
57	Customer Service and Informational (Total of line 35)				
58	Sales (Total of line 36)				
59	Administrative and General (Total of lines 37 and 46)				
60	Total Operation and Maintenance (Total of lines 50 thru 59)				
61	Other Utility Departments				
62	Operation and Maintenance				
63	TOTAL ALL Utility Dept. (Total of lines 25, 60, and 62)				
64	Utility Plant				
65	Construction (By Utility Departments)				
66	Electric Plant				
67	Gas Plant				
68	Other				
69	TOTAL Construction (Total of lines 66 thru 68)				
70	Plant Removal (By Utility Departments)				
71	Electric Plant				
72	Gas Plant				
73	Other				
74	TOTAL Plant Removal (Total of lines 71 thru 73)				
75					
76	TOTAL Other Accounts				
77	TOTAL SALARIES AND WAGES				

NORTHWEST NATURAL GAS COMPANY

Washington Supplement to FERC Form 2

December 31, 2017

Name of Respondent	This Report is:	Date of Report	Year of Report
	(1) ☒ An Original	(Mo, Da, Yr)	
Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

ANNUAL REPORT
WASHINGTON SUPPLEMENT TO FERC FORM 2
for
MULTI-STATE GAS COMPANIES

INDEX

Name of Respondent	This Report is:	Date of Report	Year of Report
	(1) ☒ An Original	(Mo, Da, Yr)	
Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

Line No.	Title of Account	Total Company Operations		Washington Operations	
		Current Year	Prior Year	Current Year	Prior Year
1	GAS SERVICE REVENUES				
2					
3	RESIDENTIAL SALES	458,762,939	400,892,165	51,148,494	40,198,408
4	COMMERCIAL SALES	229,680,586	197,732,492	19,735,075	15,709,011
5	INDUSTRIAL SALES	44,930,544	40,339,367	2,706,144	2,336,464
6	OTHER SALES	—	—	—	—
7	SALES FOR RESALE	—	—	—	—
8	TRANSPORTATION OF GAS OF OTHERS	20,351,015	19,876,956	2,363,753	2,213,346
9	OTHER OPERATING REVENUES	(1,714,115)	8,746,096	(2,313,471)	(79,729)
10					
11	TOTAL GAS SERVICE REVENUES	752,010,969	667,587,076	73,639,995	60,377,500
12					
13	THERMS OF GAS SOLD-TRANSPORTED				
14					
15	RESIDENTIAL SALES	466,326,679	369,211,302	54,321,792	42,693,480
16	COMMERCIAL SALES	274,772,356	224,817,241	23,082,577	18,548,399
17	INDUSTRIAL SALES	35,567,329	83,667,693	3,169,879	3,999,519
18	OTHER SALES (UNBILLED)	(652,709)	15,696,452	117,158	1,852,513
19	SALES FOR RESALE	—	—	—	—
20	TRANSPORTATION OF GAS OF OTHERS	409,171,739	391,604,529	20,925,171	19,405,522
21					
22	TOTAL THERMS OF GAS SOLD-TRANSPORTED	1,185,185,394	1,084,997,217	101,616,577	86,499,433
23					
24	AVERAGE NUMBER OF GAS CUSTOMERS PER MONTH				
25					
26	RESIDENTIAL SALES	662,731	651,342	73,747	71,582
27	COMMERCIAL SALES	67,417	66,439	6,735	6,423
28	INDUSTRIAL SALES	792	787	57	54
29	OTHER SALES	—	—	—	—
30	SALES FOR RESALE	—	—	—	—
31	TRANSPORTATION OF GAS OF OTHERS	392	386	41	41
32					
33					
34	TRANS. & DISTRN. MAINS - FEET (END OF YEAR)	76,351,706	75,737,499	9,765,955	9,540,670
35	NO. OF METERS IN SERV. & HELD IN RESERVE (AVE.)	819,255	808,039	81,661	79,264
36	AVERAGE B.T.U. CONTENT PER CU. FT.	1,071.7	1,074.8	1,073.6	1,077.9

Name of Respondent	This Report is:	Date of Report	Year of Report
	(1) ☒ An Original	(Mo, Da, Yr)	
Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION

Line No.	Item (a)	Total (b)
1	UTILITY PLANT	
2	In Service	
3	Plant in Service (Classified)	231,042,382
4	Property Under Capital Leases	—
5	Plant Purchased or Sold	—
6	Completed Construction not Classified	44,063,646
7	Experimental Plant Unclassified	—
8	TOTAL Utility Plant (Total of lines 3 thru 7)	275,106,028
9	Leased to Others	—
10	Held for Future Use	—
11	Construction Work in Progress	2,844,815
12	Acquisition Adjustments	—
13	TOTAL Utility Plant (Total of lines 8 thru 12)	277,950,843
14	Accumulated Provisions for Depreciation, Amortization, & Depletion	110,190,925
15	Net Utility Plant (Enter Total of line 13 less 14)	167,759,918
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION	
17	In Service:	
18	Depreciation	109,746,442
19	Amortization and Depl. of Producing Natural Gas Land and Land Rights	—
20	Amortization. of Underground Storage Land and Land Rights	—
21	Amortization. of Other Utility Plant	1,888,776
22	Salvage Work In Progress	—
23	Less Removal Work In Progress	1,444,293
24	TOTAL In Service (Total of lines 18 thru 22 less line 23)	110,190,925
25	Leased to Others	
26	Depreciation	—
27	Amortization and Depletion	—
28	TOTAL Leased to Others (Total of lines 26 and 27)	—
29	Held for Future Use	
30	Depreciation	—
31	Amortization	—
32	TOTAL Held for Future Use (Total of lines 30 and 31)	—
33	Abandonment of Leases (Natural Gas)	—
34	Amortization of Plant Acquisition Adjustment	—
35	TOTAL Accumulated Provisions (Should agree with line 14 above) (Total of lines 24, 28, 32, 33, and 34)	110,190,925

Name of Respondent	This Report is:	Date of Report	Year of Report
	(1) ☒ An Original	(Mo, Da, Yr)	
Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION (Continued)

Electric (c)	Gas (d)	Other (Specify) (e)	Common (f)	Line No.
				1
				2
	231,042,382			3
	—			4
	—			5
	44,063,646			6
	—			7
	275,106,028			8
	—			9
	—			10
	2,844,815			11
	—			12
	277,950,843			13
	110,190,925			14
	167,759,918			15
				16
				17
	109,746,442			18
	—			19
	—			20
	1,888,776			21
	—			22
	1,444,293			23
	110,190,925			24
				25
	—			26
	—			27
	—			28
				29
	—			30
	—			31
	—			32
	—			33
	—			34
	110,190,925			35

Gas Plant in Service (Accounts 101, 102, 103, and 106

1. Report below the original cost of gas plant in service according to the prescribed accounts.

2. In addition to Account 101, Gas Plant in Service (Classified), this page and the next include Account 102, Gas Plant Purchased or Sold, Account 103, Experimental Gas Plant Unclassified, and Account 106, Completed Construction Not Classified-Gas.

3. Include in column (c) and (d), as appropriate corrections of additions and retirements for the current or preceding year.

4. Enclose in parenthesis credit adjustments of plant accounts to indicate the negative effect of such accounts.

5. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c).Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d) reversals of tentative distributions of prior year's unclassified retirements. Attach supplemental statement showing the account distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Account 101 and 106 will avoid serious omissions of respondent's reported amount for plant actually in service at end of year.

6. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102. In showing the clearance of Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits to primary account classifications.

7. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirements of these pages.

8. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchaser, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give date of such filing.

SEE FOLLOWING PAGES

ACCOUNT SUMMARY BY FUNCTIONAL CLASS

NW Natural

						Period Beginning:	January 2017
						Period Ending:	December 2017
Functional Class FERC Plant Account		Beginning Balance	Additions	Retirements	Transfers	Adjustments	Ending Balance*
UTILITY							
Intangible Plant							
301	ORGANIZATION	322	—	—	—	—	322
302	FRANCHISES & CONSENTS	125	—	—	—	—	125
303.1	COMPUTER SOFTWARE	—	—	—	—	—	—
303.2	CUSTOMER INFORMATION SYSTEM	1,859,863	—	—	—	—	1,859,863
303.3	INDUSTRIAL & COMMERCIAL BIL	—	—	—	—	—	—
303.4	CRMS	—	—	—	—	—	—
303.5	POWERPLANT SOFTWARE	—	—	—	—	—	—
	Intangible Plant Subtotal*	1,860,310	—	—	—	—	1,860,310
Transmission Plant							
367	MAINS	1,054,795	59,879	—	—	—	1,114,674
	Transmission Plant Subtotal*	1,054,795	59,879	—	—	—	1,114,674
Distribution Plant							
374.1	LAND	10,389	—	—	—	—	10,389
374.2	LAND RIGHTS	27,679	—	—	—	—	27,679
375	STRUCTURES & IMPROVEMENTS	1,348,739	19,662	—	—	—	1,368,401
376.11	MAINS < 4"	75,281,776	4,735,107	(26,516)	—	—	79,990,367
376.12	MAINS 4" & >	77,411,396	10,018,748	(111,174)	—	—	87,318,971
378	MEASURING & REG EQUIP - GENER	2,130,436	102,318	—	—	—	2,232,755
379	MEASURING & REG EQUIP - GATE	1,206,729	45,644	—	—	—	1,252,374
380	SERVICES	66,796,314	4,319,869	(260,328)	—	—	70,855,855
381	METERS	10,386,272	361,934	(50,044)	—	(141,915)	10,556,247
381.2	ERT (ENCODER RECEIVER TRANS	6,566,233	147,506	(39,032)	—	141,915	6,816,622
382	METER INSTALLATIONS	6,029,071	311,501	(119,804)	—	—	6,220,768
382.2	ERT INSTALLATION (ENCODER	938,840	—	(4,737)	—	—	934,103
383	HOUSE REGULATORS	51,041	23,183	—	—	—	74,224
386	OTHER PROPERTY ON CUSTOMERS P	—	—	—	—	—	—
387.2	CALORIMETERS @ GATE STATIONS	26,630	—	—	—	—	26,630
	Distribution Plant Subtotal*	248,211,544	20,085,474	(611,634)	—	—	267,685,383

ACCOUNT SUMMARY BY FUNCTIONAL CLASS

NW Natural

						Period Beginning:	January 2017
						Period Ending:	December 2017
Functional Class		Beginning					Ending
FERC Plant Account		Balance	Additions	Retirements	Transfers	Adjustments	Balance*
UTILITY							
General Plant							
389	LAND	1,158,650	—	—	—	—	1,158,650
390	STRUCTURES & IMPROVEMENTS	1,575,582	6,672	—	—	—	1,582,254
390.1	SOURCE CONTROL PLANT	675,363	15,185	—	—	—	690,548
391.1	OFFICE FURNITURE & EQUIPMEN	16,522	—	—	—	—	16,522
391.4	CUSTOMER INFORMATION SYSTEM	—	—	—	—	—	—
392	TRANSPORTATION EQUIPMENT	631,593	—	(56,750)	—	—	574,843
394	TOOLS - SHOP AND GARAGE EQUIPMENT	88,278	—	—	—	—	88,278
396	POWER OPERATED EQUIPMENT	228,757	—	—	—	—	228,757
397.3	TELEMETERING - OTHER	101,081	—	—	—	—	101,081
397.5	TELEPHONE EQUIPMENT	—	—	—	—	—	—
398.4	INSTALLED IN LEASED BUILDINGS	4,727	—	—	—	—	4,727
	General Plant Subtotal	4,480,554	21,857	(56,750)	—	—	4,445,661
	Washington Utility Property Grand Total*	255,607,203	20,167,209	(668,385)	—	—	275,106,028

* May not foot due to rounding.

Name of Respondent	This Report is:	Date of Report	Year of Report
	(1) ☒ An Original	(Mo, Da, Yr)	
Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

Construction Work in Progress - Gas (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (Account 107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstration (see Account 107 of the Uniform System of Accounts).
3. Minor projects (less than $1,000,000) may be grouped.

Line No.	Description of Project (a)	Construction Work in Progress - Gas (Account 107) (b)	Estimated Additional Cost of Project (c)
1	Mains and Service Jobs	2,844,815	1,815,996
2			
3			
4			
5			
6			
7			
8			
9			
10			
11			
12			
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28			
29			
30			
31			
32			
33			
34			
35	**Total**	**2,844,815**	**1,815,996**

Accumulated Provision for Depreciation of Gas Utility Plant (Account 108)

1. Explain in a footnote any important adjustments during year.

2. Explain in a footnote any difference between the amount for book cost of plant retired, line 10, column (c), and that reported for gas plant in service, page 204-209, column (d), excluding retirements of nondepreciable property.

3. The provisions of Account 108 in the Uniform System of Accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.

4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

5. At lines 7 and 14, add rows as necessary to report all data. Additional rows should be numbered in sequence, e.g., 7.01, 7.02, etc.

SEE FOLLOWING PAGES

RESERVE BALANCES AND ACTIVITY BY FUNCTIONAL CLASS
NW NATURAL

Period Beginning: January 2017
Period Ending: December 2017

Functional Class FERC Plant Account		Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Loss/(Gain)	Ending Reserve*
UTILITY									
Intangible Plant									
301	ORGANIZATION	—	—	—	—	—	—	—	—
302	FRANCHISES & CONSENTS	—	—	—	—	—	—	—	—
303.1	COMPUTER SOFTWARE	3,144	—	—	—	—	—	—	3,144
303.2	CUSTOMER INFORMATION SYSTEM	1,863,073	—	—	—	—	—	—	1,863,073
303.3	INDUSTRIAL & COMMERCIAL BIL	—	—	—	—	—	—	—	—
303.4	CRMS	—	—	—	—	—	—	—	—
303.5	POWERPLANT SOFTWARE	—	—	—	—	—	—	—	—
	Intangible Plant Subtotal*	1,866,216	—	—	—	—	—	—	1,866,216
Transmission Plant									
367	MAINS	125,753	22,303	—	—	—	—	—	148,056
	Transmission Plant Subtotal*	125,753	22,303	—	—	—	—	—	148,056
Distribution Plant									
374.1	LAND	—	—	—	—	—	—	—	—
374.2	LAND RIGHTS	20,483	2,076	—	—	—	—	—	22,559
375	STRUCTURES & IMPROVEMENTS	31,086	5,847	—	—	—	—	—	36,933
376.11	MAINS < 4"	35,707,076	2,011,851	(26,516)	(64,586)	—	—	—	37,627,825
376.12	MAINS 4" & >	25,595,801	2,015,339	(111,174)	(157,674)	—	—	—	27,342,292
378	MEASURING & REG EQUIP - GENER	832,534	47,794	—	—	—	—	—	880,328
379	MEASURING & REG EQUIP - GATE	691,945	54,531	—	—	—	—	—	746,476
380	SERVICES	31,614,449	1,856,290	(260,328)	(41,353)	—	—	—	33,169,058
381	METERS	2,533,462	243,883	(50,044)	—	—	(5,623)	—	2,721,678
381.2	ERT (ENCODER RECEIVER TRANS	3,885,882	441,290	(39,032)	—	—	5,623	—	4,293,763
382	METER INSTALLATIONS	1,277,659	145,094	(119,804)	—	—	—	—	1,302,949
382.2	ERT INSTALLATION (ENCODER	609,204	62,365	(4,737)	—	—	—	—	666,832
383	HOUSE REGULATORS	8,018	1,575	—	—	—	—	—	9,593
386	OTHER PROPERTY ON CUSTOMERS P	—	—	—	—	—	—	—	—
387.2	CALORIMETERS @ GATE STATIONS	26,630	—	—	—	—	—	—	26,630
	Distribution Plant Subtotal*	102,834,228	6,887,935	(611,634)	(263,614)	—	—	—	108,846,915

RESERVE BALANCES AND ACTIVITY BY FUNCTIONAL CLASS
NW NATURAL

Period Beginning: January 2017
Period Ending: December 2017

Functional Class / FERC Plant Account		Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Loss/(Gain)	Ending Reserve*
UTILITY									
General Plant									
389	LAND	—	—	—	—	—	—	—	—
390	STRUCTURES & IMPROVEMENTS	30,913	31,044	—	—	—	—	—	61,957
390.1	SOURCE CONTROL PLANT	94,903	35,830	—	—	—	—	—	130,732
391.1	OFFICE FURNITURE & EQUIPMEN	20,592	1,317	—	—	—	—	—	21,908
391.4	CUSTOMER INFORMATION SYSTEM	—	—	—	—	—	—	—	—
392	TRANSPORTATION EQUIPMENT	408,311	34,750	(56,750)	—	—	—	—	386,310
394	TOOLS AND EQUIPMENT	27,988	6,171	—	—	—	—	—	34,159
396	POWER OPERATED EQUIPMENT	111,752	6,131	—	—	—	—	—	117,883
397.3	TELEMETERING - OTHER	16,283	71	—	—	—	—	—	16,354
397.5	TELEPHONE EQUIPMENT	—	—	—	—	—	—	—	—
398.4	INSTALLED IN LEASED BUILDINGS	4,727	—	—	—	—	—	—	4,727
	General Plant Subtotal*	715,468	115,313	(56,750)	—	—	—	—	774,031
	Washington Utility Property Grand Total*	105,541,666	7,025,550	(668,385)	(263,614)	—	—	—	111,635,218

TOTAL SUMMARY ALL UTILITY DEPRECIATION RESERVES			12/31/2017
UTILITY			
108010		(1,277,504)	
108011		80,067,744	
108012		374,008	
108013		(12,303)	
108014		—	
108015		117,883	
108100		—	
108102		32,365,391	
	SUBTOTAL*		111,635,218
ADD:			
108001	REMOVAL WORK IN PROCESS		1,444,293
	TOTAL UTILITY DEPRECIATION*		110,190,925

* May not foot due to rounding.

Name of Respondent	This Report is:	Date of Report	Year of Report
	(1) ☒ An Original	(Mo, Da, Yr)	
Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

GAS OPERATING REVENUES (Account 400)

1. Report below natural gas operating revenues for each prescribed account total. The amounts must be consistent with the detailed data on succeeding pages.

2. Revenues in columns (b) and (c) include transition costs from upstream pipelines.

3. Other Revenues in columns (f) and (g) include reservation charges received by the pipeline plus usage charges, less revenues reflected in columns (b) through (e). Include in columns (f) and (g) revenues for Accounts 480 - 495.

Line No.	Title of Account (a)	Revenues for Transition Costs and Take-or-Pay Amount for Current Year (b)	Revenues for Transition Costs and Take-or-Pay Amount for Previous Year (c)	Revenues for GRI and ACA Amount for Current Year (d)	Revenues for GRI and ACA Amount for Previous Year (e)
1	480 Residential Sales				
2	481 Commercial and Industrial Sales				
3	482 Other Sales to Public Authorities				
4	483 Sales for Resale				
5	484 Interdepartmental Sales				
6	485 Intracompany Transfers				
7	487 Forfeited Discounts				
8	488 Miscellaneous Service Revenues				
9	489.1 Revenues from Transportation of Gas of Others Through Gathering Facilities				
10	489.2 Revenues from Transportation of Gas of Others Through Transmission Facilities				
11	489.3 Revenues from Transportation of Gas of Others Through Distribution Facilities				
12	489.4 Revenues from Storing Gas of Others				
13	490 Sales of Prod. Ext. from Natural Gas				
14	491 Revenues from Natural Gas Proc. by				
15	492 Incidental Gasoline and Oil Sales				
16	493 Rent from Gas Property				
17	494 Interdepartmental Rents				
18	495 Other Gas Revenues				
19	Subtotal:				
20	496 (Less) Provision for Rate Refunds				
21	TOTAL:				

GAS OPERATING REVENUES (Account 400) (Continued)

4. If increases or decreases from previous year are not derived from previously reported figures, explain any inconsistencies in a footnote.
5. On Page 108, include information on major changes during the year, new service, and important rate increases or decreases.
6. Report the revenue from transportation services that are bundled with storage services as transportation service revenue.

Other Revenues Amount for Current Year (f)	Other Revenues Amount for Previous Year (g)	Total Operating Revenues Amount for Current Year (h)	Total Operating Revenues Amount for Previous Year (i)	Dekatherm of Natural Gas Amount for Current Year (j)	Dekatherm of Natural Gas Amount for Previous Year (k)	Line No.
51,148,494	40,198,408	51,148,494	40,198,408	5,433,630	4,389,783	1
22,441,219	18,045,475	22,441,219	18,045,475	2,775,304	2,319,608	2
—	—	—	—	—	—	3
—	—	—	—	—	—	4
—	—	—	—	—	—	5
—	—	—	—			6
101,454	80,891	101,454	80,891			7
110,115	89,435	110,115	89,435			8
—	—	—	—	—	—	9
—	—	—	—	—	—	10
2,363,753	2,213,346	2,363,753	2,213,346	2,092,517	1,940,552	11
—	—	—	—	—	—	12
—	—	—	—			13
—	—	—	—			14
—	—	—	—			15
15,386	27,455	15,386	27,455			16
—	—	—	—			17
(2,540,426)	(277,510)	(2,540,426)	(277,510)			18
73,639,995	60,377,500	73,639,995	60,377,500			19
—	—	—				20
73,639,995	60,377,500	73,639,995	60,377,500			21

OTHER GAS REVENUES (ACCOUNT 495)

Report below transactions of $250,000 or more included in Account 495, Other Gas Revenues. Group all transactions below $250,000 in one amount and provide the number of items.

Line No.	Description of Transaction (a)	Amount (b)
1	Washington Amortizations	(2,058,393)
2	Washington GREAT Program	(472,237)
3	Other Miscellaneous Items	(9,796)
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30	**Total**	(2,540,426)

Depreciation, Depletion and Amortization of Gas Plant (Accts 403, 404.1, 404.2, 404.3, 405) (Except Amortization of Acquisition Adjustments)

1. Report in Section A the amounts of depreciation expense, depletion and amortization for the accounts indicated and classified according to the plant functional groups shown.

2. Report in Section B, column (b) all depreciable or amortizable plant balances to which rates are applied and show a composite total. (If more desirable, report by plant account, subaccount or functional classifications other than those pre-printed in column (a). Indicate in a footnote the manner in which column (b) balances are obtained. If average balances are used, state the method of averaging used. For column (c) report available information for each plant functional classification listed in column (a). If composite depreciation accounting is used, report available information called for in columns (b) and (c) on this basis. Where the unit-of-production method is used to determine depreciation charges, show in a footnote any revisions made to estimated gas reserves.

3. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state in a footnote the amounts and nature of the provisions and the plant items to which related.

See following pages

RESERVE BALANCES AND ACTIVITY BY FUNCTIONAL CLASS

NW NATURAL

Period Beginning: January 2017

Period Ending: December 2017

Functional Class FERC Plant Account		Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Loss/(Gain)	Ending Reserve*
UTILITY									
Intangible Plant									
301	ORGANIZATION	—	—	—	—	—	—	—	—
302	FRANCHISES & CONSENTS	—	—	—	—	—	—	—	—
303.1	COMPUTER SOFTWARE	3,144	—	—	—	—	—	—	3,144
303.2	CUSTOMER INFORMATION SYSTEM	1,863,073	—	—	—	—	—	—	1,863,073
303.3	INDUSTRIAL & COMMERCIAL BIL	—	—	—	—	—	—	—	—
303.4	CRMS	—	—	—	—	—	—	—	—
303.5	POWERPLANT SOFTWARE	—	—	—	—	—	—	—	—
	Intangible Plant Subtotal*	1,866,216	—	—	—	—	—	—	1,866,216
Transmission Plant									
367	MAINS	125,753	22,303	—	—	—	—	—	148,056
	Transmission Plant Subtotal*	125,753	22,303	—	—	—	—	—	148,056
Distribution Plant									
374.1	LAND	—	—	—	—	—	—	—	—
374.2	LAND RIGHTS	20,483	2,076	—	—	—	—	—	22,559
375	STRUCTURES & IMPROVEMENTS	31,086	5,847	—	—	—	—	—	36,933
376.11	MAINS < 4"	35,707,076	2,011,851	(26,516)	(64,586)	—	—	—	37,627,825
376.12	MAINS 4" & >	25,595,801	2,015,339	(111,174)	(157,674)	—	—	—	27,342,292
378	MEASURING & REG EQUIP - GENER	832,534	47,794	—	—	—	—	—	880,328
379	MEASURING & REG EQUIP - GATE	691,945	54,531	—	—	—	—	—	746,476
380	SERVICES	31,614,449	1,856,290	(260,328)	(41,353)	—	—	—	33,169,058
381	METERS	2,533,462	243,883	(50,044)	—	—	(5,623)	—	2,721,678
381.2	ERT (ENCODER RECEIVER TRANS	3,885,882	441,290	(39,032)	—	—	5,623	—	4,293,763
382	METER INSTALLATIONS	1,277,659	145,094	(119,804)	—		—		1,302,949
382.2	ERT INSTALLATION (ENCODER	609,204	62,365	(4,737)	—		—		666,832
383	HOUSE REGULATORS	8,018	1,575	—	—	—	—	—	9,593
386	OTHER PROPERTY ON CUSTOMERS P	—	—	—	—	—	—	—	—
387.2	CALORIMETERS @ GATE STATIONS	26,630	—	—	—	—	—	—	26,630
	Distribution Plant Subtotal*	102,834,228	6,887,935	(611,634)	(263,614)	—	—	—	108,846,915

RESERVE BALANCES AND ACTIVITY BY FUNCTIONAL CLASS

NW NATURAL

Period Beginning: January 2017

Period Ending: December 2017

Functional Class FERC Plant Account		Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Loss/(Gain)	Ending Reserve*
UTILITY									
General Plant									
389	LAND	—	—	—	—	—	—	—	—
390	STRUCTURES & IMPROVEMENTS	30,913	31,044	—	—	—	—	—	61,957
390.1	SOURCE CONTROL PLANT	94,903	35,830	—	—	—	—	—	130,732
391.1	OFFICE FURNITURE & EQUIPMEN	20,592	1,317	—	—	—	—	—	21,908
391.4	CUSTOMER INFORMATION SYSTEM	—	—	—	—	—	—	—	—
392	TRANSPORTATION EQUIPMENT	408,311	34,750	(56,750)	—	—	—	—	386,310
394	TOOLS AND EQUIPMENT	27,988	6,171	—	—	—	—	—	34,159
396	POWER OPERATED EQUIPMENT	111,752	6,131	—	—	—	—	—	117,883
397.3	TELEMETERING - OTHER	16,283	71	—	—	—	—	—	16,354
397.5	TELEPHONE EQUIPMENT	—	—	—	—	—	—	—	—
398.4	INSTALLED IN LEASED BUILDINGS	4,727	—	—	—		—		4,727
	General Plant Subtotal*	715,468	115,313	(56,750)	—	—	—	—	774,031
	Washington Utility Property Grand Total*	105,541,666	7,025,550	(668,385)	(263,614)	—	—	—	111,635,218

TOTAL SUMMARY ALL UTILITY DEPRECIATION RESERVES			12/31/2017
UTILITY			
108010		(1,277,504)	
108011		80,067,744	
108012		374,008	
108013		(12,303)	
108014		—	
108015		117,883	
108100		—	
108102		32,365,391	
	SUBTOTAL*		111,635,218
ADD:			
108001	REMOVAL WORK IN PROCESS		1,444,293
	TOTAL UTILITY DEPRECIATION*		110,190,925

* May not foot due to rounding.

GAS ACCOUNT - NATURAL GAS

1. The purpose of this schedule is to account for the quantity of natural gas received and delivered by the respondent.
2. Natural gas means either natural gas unmixed or any mixture of natural and manufactured gas.
3. Enter in column (c) the Dth as reported in the schedules indicated for the items of receipts and deliveries.
4. Indicate in a footnote the quantities of bundled sales and transportation gas and specify the line on which such quantities are listed.
5. If the respondent operates two or more systems which are not interconnected, submit separate pages for this purpose. Use copies of pages 520.
6. Indicate by footnote the quantities of gas not subject to Commission regulation which did not incur FERC regulatory costs by showing (1) the local distribution volumes another jurisdictional pipeline delivered to the local distribution company portion of the reporting pipeline (2) the quantities that the reporting pipeline transported or sold through its local distribution facilities or intrastate facilities and which the reporting pipeline received through gathering facilities or intrastate facilities, but not through any of the interstate portion of the reporting pipeline, and (3) the gathering line quantities that were not destined for interstate market of that were not transported through any interstate portion of the reporting pipeline.
7. Indicate in a footnote the specific gas purchase expense account(s) and related to which the aggregate volumes reported on Line 3 relate.
8. Indicate in a footnote (1) the system supply quantities of gas that are stored by the reporting pipeline, during the reporting year and also reported as sales, transportation and compression volumes by the reporting pipeline during the same reporting year, (2) the system supply quantities of gas that are stored by the reporting pipeline during the reporting year which the reporting pipeline intends to sell or transport in a future reporting year, and (3) contract storage quantities.
9. Indicate the volumes of pipeline production field sales that are included in both the company's total sales figure and the company's total transportation figure. Add additional information as necessary to the footnotes.

Line No.	Item (a)	Ref. Page No. (b)	Total Amount of Dth (c)
1	NAME OF SYSTEM:		
2	GAS RECEIVED		
3	Gas Purchases (Accounts 800-805)		—
4	Gas of Others Received for Gathering (Account 489.1)	303	8,162,040
5	Gas of Others Received for Transmission (Account 489.2)	305	N/A
6	Gas of Others Received for Distribution (Account 489.3) Transportation	301	2,092,517
7	Gas of Others Received for Contract Storage (Account 489.4)	307	N/A
8	Gas of Other Received for Production/Extraction/Processing (Account 490 and 491)		N/A
9	Exchanged Gas Received from Others (Account 806)	328	N/A
10	Gas Received as Imbalances (Account 806)	328	N/A
11	Receipts of Respondent's Gas Transported by Others (Account 858)	332	N/A
12	Other Gas Withdrawn from Storage (Explain)		—
13	Gas Received from Shippers as Compressor Station Fuel		—
14	Gas Received from Shippers as Lost and Unaccounted for		—
15	Other Receipts (Specify) LPG		—
16	Total Receipts (Total of lines 3 thru 14)		10,254,557
17	GAS DELIVERED		
18	Gas Sales (Accounts 480-495)		8,197,219
19	Deliveries of Gas Gathered for Others (Account 489.1)	303	N/A
20	Deliveries of Gas Transported for Others (Account 489.2)	305	N/A
21	Deliveries of Gas Distributed for Others (Account 489.3) Transportation	301	2,092,517
22	Deliveries of Contract Storage Gas (Account 489.4)	307	N/A
23	Gas of Other Delivered for Production/Extraction/Processing (Account 490 and 491)		N/A
24	Exchange Gas Delivered to Others (Account 806)	328	N/A
25	Gas Delivered as Imbalances (Account 806)	328	N/A
26	Deliveries of Gas to Others for Transportation (Account 858)	332	N/A
27	Other Gas Delivered to Storage (Explain)		—
28	Gas Used for Compressor Station Fuel		N/A
29	Other Deliveries (Specify) Co Use	331	11,716
30	Total Deliveries (Total of lines 17 thru 27)		10,301,452
31	GAS LOSSES AND GAS UNACCOUNTED FOR		
32	Gas Losses and Gas Unaccounted For		(46,895)
33	TOTALS		
34	Total Deliveries, Gas Losses & Unaccounted for (Total of lines 30 and 32)		10,254,557

Name of Respondent	This Report is:	Date of Report	Year of Report
	(1) ☒ An Original	(Mo, Da, Yr)	
Northwest Natural Gas Company	(2) ☐ A Resubmission		December 31, 2017

EXECUTIVE COUNT BY CLASS AND TOTAL SALARIES BY CLASS

1. Pursuant to RCW 80.04.080, report below the number of employees by class (per company definition to be provided),

Line No.	Employee Class (a)	Number of Employees (b)	Total Salaries and Wages Paid Each Class[1] (c)
1	Officers & Exempt	517	52,057,460
2	Bargaining Unit	629	47,002,786
3			
4			
5			
Total		1,146	99,060,246

1) Salaries and wages do not include bonuses paid.

NW Natural®

2017 ANNUAL REPORT

GROWTH
SUSTAINABILITY
INNOVATION



» NW NATURAL 2017 **ANNUAL REPORT**

With an unwavering commitment to our customers and a clear-eyed focus on the future, 2017 was a pivotal year for NW Natural.

We welcomed new customers at the fastest rate in a decade; we made progress on an important expansion project; we continued to invest in our distribution system — one of the most modern in the nation; we announced plans to expand into the water utility sector; and once again, our customers rewarded us with high satisfaction ratings.

For nearly 160 years, leadership has been a hallmark of NW Natural's success — in our industry, in our region and in the communities we serve. That, coupled with innovation, has made us resilient in a changing world.

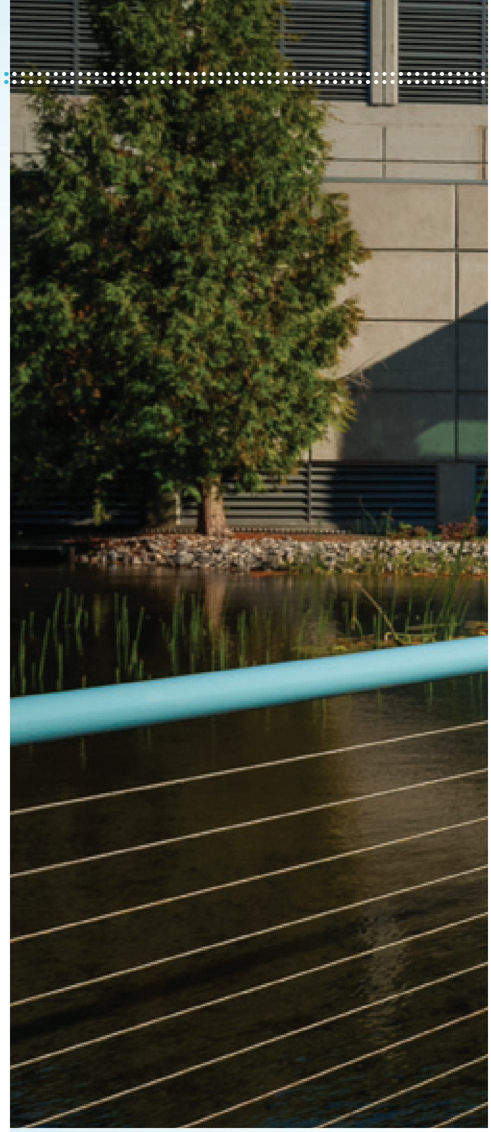
But leadership and progress require balancing interests, and, at times, making difficult decisions. In late 2017, we completed a comprehensive review of our Gill Ranch storage facility in California. Ultimately, we determined that Gill Ranch is no longer central to our broader utility strategy, which is focused on providing stable, regulated earnings growth for shareholders.

Going forward, we will continue pursuing all strategic options to maximize its value, as we remain focused on operating the facility safely and serving our current customers.

Financially in 2017, we reported a loss of $1.94 per share compared to earnings of $2.12 per share for 2016. This decrease reflects the noncash, after-tax $142 million impairment of Gill Ranch, partially offset by a noncash $21 million benefit from federal tax reform legislation.

Excluding these items on a non-GAAP basis, we delivered strong earnings and performed very well. Adjusted net income was $2.24 per share for 2017,[1] up 5 cents compared to $2.19 per share for 2016.[2]

Reflecting on the past year, I'm proud of the exceptional work of our leadership team and employees to position us for growth and sustainable success.



» CORPORATE **PROFILE**

NW NATURAL (NYSE: NWN) is a 159-year-old natural gas distribution company headquartered in Portland, Oregon.

NW NATURAL serves nearly 740,000 utility customers in Oregon and Southwest Washington and provides natural gas storage to customers on the West Coast. In keeping with its steady growth strategy, the company has increased dividends paid to shareholders for 62 consecutive years.

DAVID ANDERSON at Portland's Columbia Boulevard Wastewater Treatment Plant. In 2017 the city announced it will build a renewable natural gas (RNG) processing facility and vehicle fueling station at the site in partnership with NW Natural.

2017 **HIGHLIGHTS**

- Added over 12,700 new customers for an annual growth rate of 1.8 percent, bringing our customer base to nearly 740,000 — and marking 2017 as the highest growth rate in a decade.
- Reduced residential customer rates for the third year in a row. Oregon customers received a cumulative rate decrease of 15 percent over the past three years on top of annual bill credits, and Washington customer rates dropped a total of 18 percent.
- Earned the highest customer satisfaction score for the fifth year in a row among large utilities in the West in the J.D. Power Gas Utility Residential Customer Satisfaction Study. This is the 10th time in 11 years NW Natural has scored second or higher in the nation. We also earned the highest customer satisfaction score among utilities in the West in the J.D. Power Gas Utility Business Customer Satisfaction Study.
- Completed major components of the North Mist gas storage expansion — a multiyear $132 million project — one of the largest projects in NW Natural history.
- Invested $214 million of capital expenditures for utility customer growth, system reliability and improvements.
- Announced our expansion into the regulated water utility sector with planned acquisitions in Oregon and Idaho, which will add about 6,500 water customers. While these transactions are not material to our financial results, this is the first step in our broader water strategy.
- Filed the first Oregon general rate case in six years.
- Increased dividends paid for the 62nd consecutive year, one of the longest dividend increase records of any company on the NYSE.

[1] Adjusted measures for 2017 are non-GAAP and exclude the noncash effects of the Gill Ranch impairment and the noncash benefit from tax reform recognized in 2017. See Financial Overview on page 8 for reconciliation.

[2] Adjusted measures for 2016 are non-GAAP and exclude the noncash effects of a regulatory environmental disallowance recognized in the first quarter of 2016. See Financial Overview on page 8 for reconciliation.

« NW Natural field crews at Training Town. The mock neighborhood offers hands-on, scenario-based training and replicates real-world conditions.

SAFETY IN ALL THINGS

System Safety, Employee Training & Preparedness

NW Natural is focused on operating a safe, reliable system and delivering outstanding service for our customers and communities.

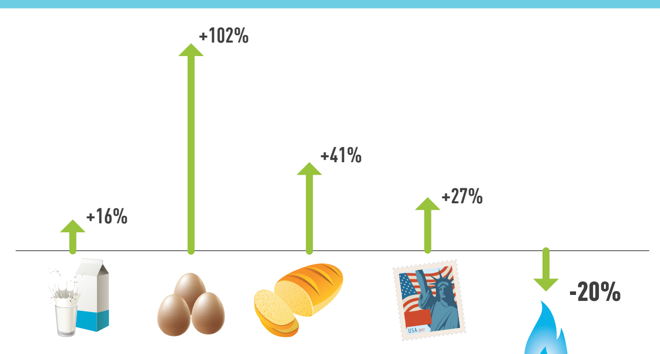
In 2017, we worked on upgrades to boost our distribution system reliability and support our fastest-growing community in Clark County, Washington. This project, estimated at $25 million, is nearly complete, with final work expected to be done in 2018.

We also finished refurbishing two liquefied natural gas (LNG) storage facilities, which are critical for delivering natural gas on the coldest winter days. In 2017, we completed a multiyear $25 million upgrade at our Newport LNG facility, originally built in 1977. At our Portland LNG facility, built in 1969, we completed improvements totaling just under $10 million.

Equipping our employees to respond to emergencies goes hand in hand with keeping our system safe. NW Natural field employees regularly participate in extensive training at our state-of-the-art training center in Sherwood, Oregon.

We offer hands-on, scenario-based training programs to first responders — teaching them about natural gas safety and how to work together effectively during a gas emergency. In 2017, we hosted over 80 trainings for more than 1,200 local firefighters, and we plan to increase that number in 2018.

The cost of natural gas is about 20% lower than it was 15 years ago.



Source: Bureau of Labor Statistics

We upgraded facilities across our service territory to retrofit, expand or relocate service centers so crews are positioned to respond to incidents quickly and serve our growing customer base effectively.

We also continued our focus on cybersecurity to ensure NW Natural's online systems are protected with the technology we need to safeguard our infrastructure. In 2017, we advanced our cybersecurity efforts by implementing additional data encryption, investing in industrial control systems infrastructure, and increasing employee awareness and training.

Customer Satisfaction LEADS TO **GROWTH**

Every day, our employees work diligently to deliver safe, reliable energy and best-in-class service. It's why we've earned the trust of customers and the communities we serve.

Once again, we're proud that NW Natural earned the highest customer satisfaction score among large utilities in the West in the 2017 J.D. Power Gas Utility Residential Customer Satisfaction Study. This marks the 10th time in 11 years that NW Natural has posted among the top two scores for residential customer satisfaction in the nation.

NW Natural also ranked first in the West in the 2017 J.D. Power Gas Utility Business Customer Satisfaction Study.

The value of our product undoubtedly influences how satisfied our customers feel. The cost of natural gas continued to drop nationally, benefiting customers. For the third year in a row, we reduced the rates our customers pay. This winter, Oregon residential customers saw their bills drop by 6.4 percent, and Washington residential customers enjoyed savings of 3.1 percent. In fact, our customers are paying 20 percent less for natural gas today than they did 15 years ago.

Lower prices continue to strengthen our competitive position. For the typical home we serve, heating with a natural gas furnace provides up to a 70 percent price advantage over heating with an electric or oil furnace.

NW Natural's Customer Contact Center receives approximately one million calls each year.

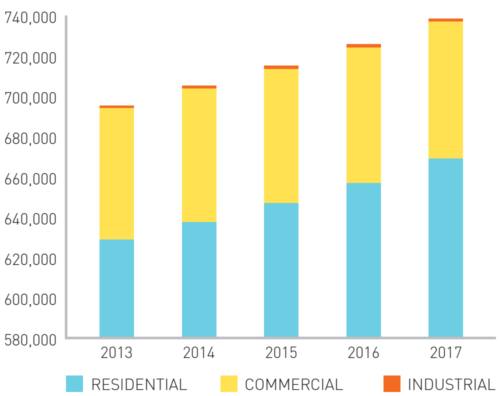
These advantages — coupled with the strong Pacific Northwest economy — have helped us convert and attract new customers to natural gas. At year-end, we reported more than 12,700 new customers, equating to a 1.8 percent annual growth rate — our best performance in a decade.

We also made inroads into the multifamily sector — which has been historically underserved by natural gas — through a comprehensive effort to make it easier for developers to build with natural gas with equipment incentives, streamlined gas infrastructure designs and promotional support.

In July 2017, the Public Utility Commission of Oregon (OPUC) approved a new multifamily tariff specifically designed for mixed-use developments — buildings with commercial and residential customers — to install natural gas more easily.

We will continue to pursue growth in all sectors in 2018.

UTILITY CUSTOMERS AT YEAR-END



We added 12,728 new customers in 2017, and now serve nearly 740,000 customers.

ENGAGING CONSTRUCTIVELY with Regulators

In December 2017, after careful consideration, we filed a rate case in Oregon for the first time in six years.

We have requested a 4 percent increase to company revenues, after an adjustment for the conservation tariff deferral, to cover our costs to operate and maintain the natural gas distribution system and continue to provide customers with safe, reliable service.

The OPUC and other stakeholders will review our filing through a process that could take up to 10 months, with new rates likely effective Nov. 1, 2018.

Companies across the country adopted the Federal Tax Cuts and Jobs Act at the end of December 2017. For NW Natural, this meant an earnings increase of $21 million related to nonregulated activities. We have a request to Washington and Oregon commissions to allow us to return the regulated utility's overall net benefits from tax reform to customers. We amended our Oregon rate case to address the impact of the lower tax rate and will work closely with the regulators in the coming months to determine the best path forward.

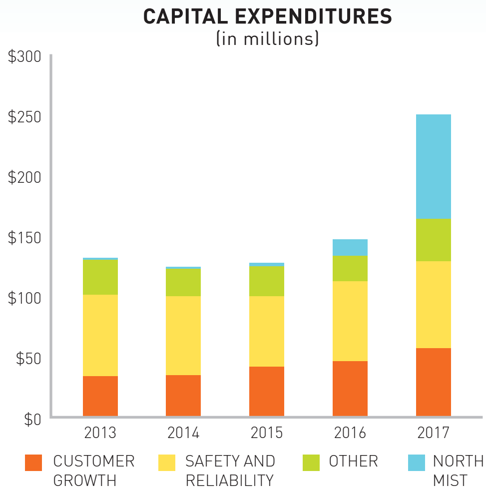
Construction of the 16-inch portion of the pipeline for the North Mist Expansion project is complete.

BUILDING THE FUTURE

Abundant and clean-burning natural gas is a critical resource that is facilitating a smooth transition to a low-carbon energy future across the country.

An exciting example is a project to expand our natural gas storage infrastructure in Mist, Oregon, which has been integral to our ability to support reliable energy service in our region since the 1980s. This regulated gas storage facility is uniquely situated with limited competition from other facilities and is highly valued due to its premium Northwest location. The Mist facility is once again proving its value with our expansion to supply unique, no-notice service that Portland General Electric (PGE) can draw on rapidly to integrate more wind power into the grid, ensuring reliable natural gas backup response.

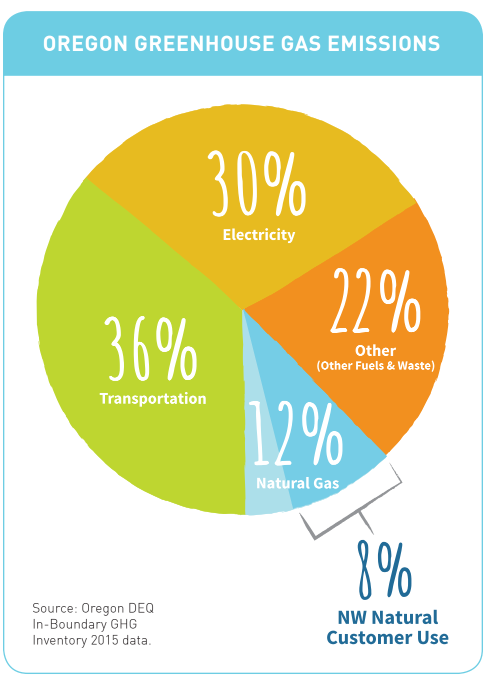
NW Natural Environmental Management and Sustainability Director Bill Edmonds with President and CEO David Anderson. »



Total investment in capital expenditures during 2017 was more than $250 million on an accrual basis.

There are three major components to this $132 million project: a new underground reservoir providing up to 2.5 billion cubic feet of available storage, an additional compressor station, and a new dedicated 13-mile pipeline to connect NW Natural's facility to PGE's Port Westward industrial park.

The investment will be included in rates under an established tariff when it is placed into service with an initial 30-year contract with options to extend totaling up to an additional 50 years upon mutual agreement.



LOW CARBON PATHWAY

Just as we're able to support renewable energy with the North Mist project, we know there are other ways NW Natural can help the region move to a low-carbon future.

Today, natural gas is the cleanest option to reliably meet our region's biggest energy needs. In Oregon, NW Natural delivers more energy over a year than any other utility, yet the use of natural gas — in our customers' homes, businesses and industry — accounts for about 8 percent of Oregon's total greenhouse gas emissions.

While we think that's a pretty efficient starting point, we believe we can do even better. It's why we set a voluntary goal of 30 percent carbon emissions savings by 2035, with a starting point of 2015 emission levels.

In 2017, we identified new opportunities to proactively reduce emissions using our existing infrastructure — one of the most modern, tightest pipeline systems in the nation.

We are especially excited about a renewable natural gas (RNG) project with the City of Portland. Announced in April 2017, the city is building an RNG production facility at its largest wastewater treatment plant to recover and clean biogas to meet our pipeline quality standards. A portion of the resulting RNG will be used to fuel heavy-duty vehicles locally, and the rest will be injected into NW Natural's existing pipeline system.

NW Natural built and installed the vehicle fueling station in 2017 and will maintain it for the city. We expect the entire project to be operational by early 2019. We're proud to partner with the City of Portland on its single largest climate action effort to date.

Collaboration is a pivotal part of reaching our carbon savings goal — and we're working on many fronts up and down the natural gas

value chain. Because our customers are key partners, we launched a multiyear outreach campaign — Less We Can — inviting them to join us in working toward a low-carbon future. We are working in the communities we serve and have shared the company's low-carbon vision with more than 100 policymakers and stakeholders.

In 2017, NW Natural also hosted the region's first RNG conference, celebrated 10 years of our Smart Energy carbon offset program, and joined the Natural Gas Supply collaborative to influence upstream production practices.

But these steps are just part of the story. We are also focused on new technologies to reduce our emissions footprint. Power-to-Gas is a cutting-edge process that captures surplus wind and solar energy and converts it to RNG or hydrogen through electrolysis. This renewable energy could be stored and then blended into our pipeline system to one day serve homes, businesses and vehicles.

FUTURE **OPPORTUNITIES**

Looking to the future, we remain focused on growing our natural gas utility business and examining opportunities that are a good fit for our expertise, create value and provide a similar risk profile to our investors.

We took an exciting first step in December 2017 when we announced our expansion into the regulated water sector with planned acquisitions of two water utilities with nearly 6,500 customers in Oregon and Idaho. We view regulated water utility opportunities as an excellent strategic fit for our company. NW Natural's core competencies — customer service, safety, environmental stewardship, reliability and managing critical distribution infrastructure — are directly applicable to the water utility business.

With substantial investment opportunities in the water sector over the long term, we will be working to build out this broader strategy in the coming years.

To better respond to growth opportunities, like our regulated water strategy, we are seeking a corporate holding company structure. This structure is widely used, particularly among utilities, and would allow us to further serve the best interests of shareholders by providing a more agile and efficient platform to pursue new growth opportunities. Our business operations and strategy would not change — we remain focused on stable, utility-type earnings growth for investors and safe, reliable service for our customers.

Idaho Falls is one of two locations where NW Natural plans to acquire a water utility.

GROWTH TODAY AND TOMORROW

Leading a company of nearly 1,200 employees who live our core values and share a common vision for the future inspires me every day. Their dedication, innovation and energy fuel our success and keep us nimble.

We made tough decisions and achieved great things in 2017. I look forward to building on what we've created — a strong foundation positioned for sustainable growth. I'm confident we will make the most of the opportunities ahead.

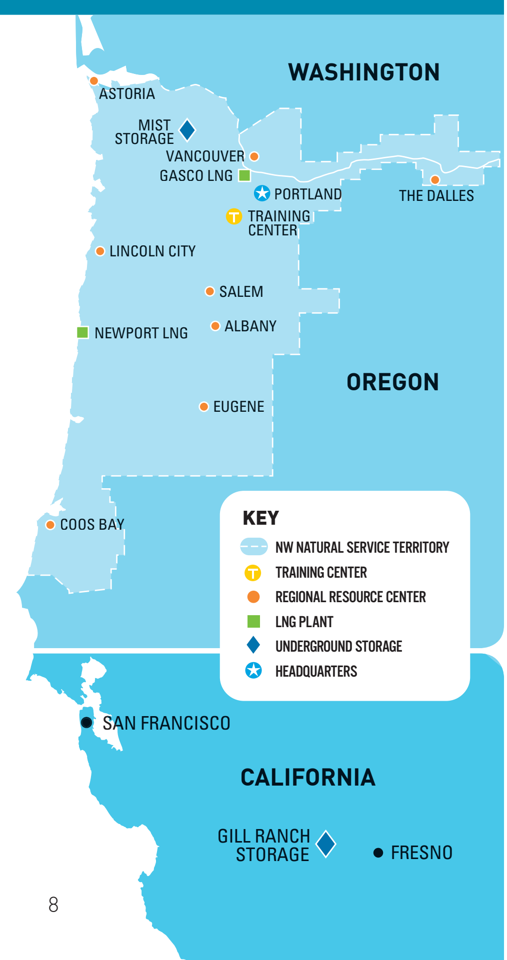
NW Natural has consistently led the industry on many fronts: environmental stewardship, system efficiency and modernization, customer service, and commitment to our communities. We take this legacy seriously and will continue to focus on delivering the highest level of performance.

Thank you for your confidence and trust in NW Natural. We look forward to working on your behalf in the year ahead.

David H. Anderson

David H. Anderson
President and Chief Executive Officer

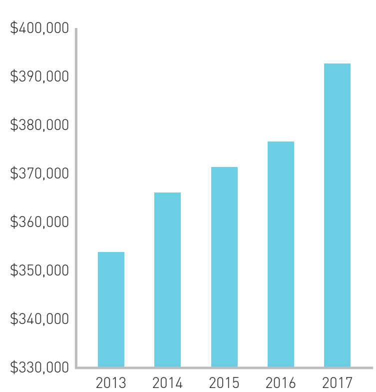
» SERVICE TERRITORY AND STORAGE FACILITIES



» FINANCIAL **OVERVIEW**

	2017	2016
EARNINGS		
Financial facts ($000):		
Operating revenues	762,173	675,967
Utility margin[1]	392,632	376,591
Net income (loss)	(55,623)	58,895
Adjusted net income	64,470[2]	60,891[3]
COMMON STOCK		
Shareholder data (000):		
Average shares outstanding–diluted	28,669	27,779
Year-end shares outstanding	28,736	28,630
Per share data ($):		
Diluted earnings (loss)	(1.94)	2.12
Adjusted diluted earnings	2.24[2]	2.19[3]
Dividends paid	1.88	1.87
Book value at year-end	25.85	29.71
Market value at year-end	59.65	59.80
UTILITY OPERATING HIGHLIGHTS		
Gas deliveries (000 therms)	1,240,293	1,084,996
Degree days	4,553	3,551
Customers at year-end	737,874	725,146
Employees at year-end	1,146	1,108
DIVIDENDS PAID ON COMMON STOCK (per share)		
Payment date		
February	$0.4700	$0.4675
May	0.4700	0.4675
August	0.4700	0.4675
November	0.4725	0.4700
Total dividends paid	$1.8825	$1.8725

UTILITY MARGIN
(in $000)



Utility margin increased $16.0 million to $392.6 million in 2017.

DIVIDENDS PAID PER SHARE
($)

Annual dividends paid per share in 2017 increased for the 62nd consecutive year. The current indicated annual dividend is $1.89 per share.

[1] References to the utility margin refer to utility segment.

[2] Adjusted consolidated net income and EPS for 2017 are non-GAAP financial measures that exclude the Gill Ranch impairment of $192.5 million pretax or $141.5 million after-tax and the $21.4 million benefit related to implementing tax reform. The after-tax impairment is calculated using the combined federal and state statutory tax rate of 26.5%. EPS is calculated using 28.7 million diluted shares.

[3] Adjusted consolidated net income and EPS for 2016 are non-GAAP financial measures that exclude the regulatory environmental disallowance of $3.3 million pretax or $2.0 million after-tax. The after-tax disallowance is calculated using the combined federal and state statutory tax rate of 39.5%. EPS is calculated using 27.8 million diluted shares.

CORPORATE **OFFICERS**

DAVID H. ANDERSON
President and
Chief Executive Officer

FRANK BURKHARTSMEYER
Senior Vice President and
Chief Financial Officer

LEA ANNE DOOLITTLE
Senior Vice President and
Chief Administrative Officer

JAMES DOWNING
Vice President and
Chief Information Officer

SHAWN M. FILIPPI
Vice President, Chief Compliance
Officer and Corporate Secretary

KIMBERLY HEITING
Senior Vice President
Operations and
Chief Marketing Officer

THOMAS J. IMESON
Vice President Public Affairs

JUSTIN B. PALFREYMAN
Vice President, Strategy and
Business Development

LORI L. RUSSELL
Vice President Utility Services

MARDILYN SAATHOFF
Senior Vice President,
Regulation and General Counsel

BRODY J. WILSON
Vice President,
Chief Accounting Officer,
Controller and Treasurer

GRANT M. YOSHIHARA
Senior Vice President
Utility Operations

OUR **MISSION**

We provide safe, reliable and affordable energy in an environmentally responsible way to better the lives of the public we serve.

OUR **CORE VALUES**

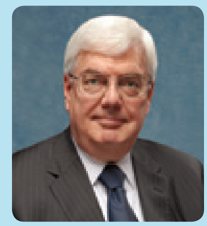
Integrity
Safety
Service Ethic
Caring
Environmental Stewardship

BOARD OF **DIRECTORS**

DAVID H. ANDERSON
President and Chief Executive
Officer, NW Natural

TIMOTHY P. BOYLE
President and Chief Executive
Officer, Columbia Sportswear
Company

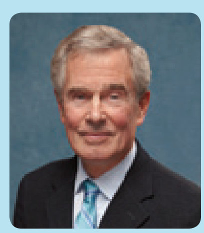
MARTHA L. "STORMY" BYORUM
Chief Executive Officer,
Cori Investment Advisors, LLC



JOHN D. CARTER
Chairman of the Board,
Schnitzer Steel Industries, Inc.

MARK S. DODSON
Former Chief Executive
Officer, NW Natural

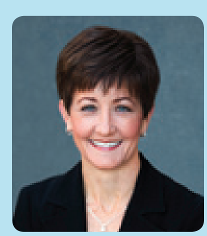
C. SCOTT GIBSON
President, Gibson Enterprises



TOD R. HAMACHEK
Chairman of the Board,
NW Natural

JANE L. PEVERETT
Former President and Chief
Executive Officer, British Columbia
Transmission Corporation

KENNETH THRASHER
Chairman of the Board,
Compli Corporation



MALIA H. WASSON
Former Executive
Vice President of Commercial
Banking, U.S. Bank

CORPORATE **INFORMATION**

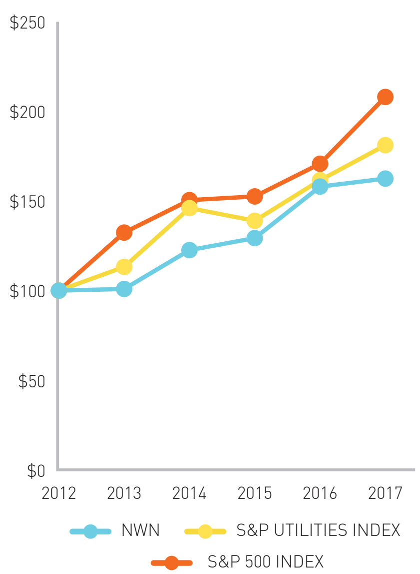
Notice of Annual Meeting

The 2018 Annual Meeting will be held at 2 p.m., Thursday, May 24, at the company's headquarters, One Pacific Square, 220 NW 2nd Ave., 4th floor, Portland, Oregon 97209. A meeting notice and proxy statement will be sent to all shareholders in April. If you plan to attend the annual meeting, you will need to detach and retain the admission ticket attached to your proxy card mailed or emailed to you with the notice of the annual meeting and the proxy statement. As space is limited, you may bring only one guest to the meeting. If you hold your stock through a broker, bank or other nominee, please bring a legal proxy or other evidence to the meeting showing that you owned NW Natural Common Stock as of the record date, April 5, 2018, and we will provide you with an admission ticket. A form of government-issued photograph identification will be required for both you and your guest to enter the meeting.

Dividend reinvestment and direct stock purchase plan

Participants may make an initial investment in company stock and common shareholders of record may reinvest all or part of their dividends in additional shares under the company's plan. Cash purchases may also be made. Participants in the plan bear the cost of brokerage fees and commissions for shares purchased on the open market to fulfill purchases under the plan. A prospectus will be sent upon request.

COMPARISON OF FIVE-YEAR CUMULATIVE TOTAL RETURN
(Based on $100 invested on 12/31/2012)



Total shareholder return (annualized) over the five years ending December 31, 2017 for NW Natural was 10.20%, compared to Standard & Poor's (S&P) Utilities Index return of 12.61%, and the S&P 500 Index return of 15.77%.

Scheduled dividend payment dates

Subject to Board approval, the following dates are scheduled for dividend payment:
February 15, 2018
May 15, 2018
August 15, 2018
November 15, 2018

Certifications

The Chief Executive Officer certified to the NYSE on June 26, 2017, that as of that date, he was not aware of any violation by the company of NYSE's corporate governance listing standards, and the company had filed with the Securities and Exchange Commission (SEC), as exhibits 31.1 and 31.2 to its Annual Report on Form 10-K for the year ended December 31, 2016, the certificates of the Chief Executive Officer and the Chief Financial Officer of the company certifying the quality of the company's public disclosure. For the year ended December 31, 2017, the certificates of the Chief Executive Officer and Chief Financial Officer are attached as exhibits 31.1 and 31.2 to the Form 10-K included in this Annual Report.

Contact the NW Natural Board

Concerns may be directed to the nonmanagement directors by writing to NW Natural Board of Directors, c/o Corporate Secretary.

Forward-looking statements

The statements made in this Annual Report that are not purely historical, including statements regarding plans, goals, strategies, success, opportunities, dividends, earnings, financial value, future demand or preference for gas, the future of clean energy and the role of natural gas in it, renewable natural gas, power to gas, commodity costs, customer rates and service, competitive position, revenues, customer and business growth, capital expenditures, Mist storage expansion project, including but not limited to cost and timelines, emergency preparedness, cybersecurity, system reliability, safety, environmental stewardship, regulatory proceedings and actions, including, but not limited to our rate case and the timing and results thereof, the regional economy, expansion into the water sector, Gill Ranch strategic options, planned acquisitions, multifamily sector, system modernization and efficiency, corporate structure including reorganization as a holding company, and effects of legislation, including the Federal Tax Cuts and Jobs Act, are forward-looking statements within the "safe harbor" provisions of the Private Securities Litigation Reform Act of 1995. NW Natural's actual results could differ materially from those anticipated in these forward-looking statements as a result of risks and uncertainties, including those described in the attached report on Form 10-K. For a more complete description of these risks and uncertainties, please refer to our filings with the SEC on Forms 10-K and 10-Q.

Request for publications

The following publications may be obtained without charge by contacting the Corporate Secretary at NW Natural's address: Annual Report; Form 10-K; Form 10-Q; Corporate Governance Standards; Director Independence Standards; Code of Ethics; and Board Committee Charters. These publications, as well as other filings made with the SEC, are also available on our website at nwnatural.com. Our SEC filings are also available by request through the SEC by mail at U.S. Securities and Exchange Commission, Office of FOIA/PA Operations, 100 F Street, N.E., Washington, D.C. 20549, or online at sec.gov. You can obtain information about access to the Public Reference Room and how to access or request records by calling the SEC at 1-800-SEC-0330.

NW Natural®

Produced by NW Natural's Corporate Communications

PHOTO CREDITS ANDY BAUER - page 5, North Mist expansion pipeline; DALE HEADRICK - page 2, J.D. Power Awards; page 4, Training Town, System Operations; page 5, Customer Contact Center; page 6, Bill Edmonds and David Anderson; ROBBIE McCLARAN - page 3, David Anderson • **PRINTING** Donnelley Financial Solutions

Form 10-K

Annual Report

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2017

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from ___________ to____________

Commission file number 1-15973

NW Natural

NORTHWEST NATURAL GAS COMPANY
(Exact name of registrant as specified in its charter)

Oregon	**93-0256722**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

220 N.W. Second Avenue, Portland, Oregon 97209
(Address of principal executive offices) (Zip Code)
Registrant's telephone number, including area code: **(503) 226-4211**

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None.

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
Yes [X] No [ ]

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.
Yes [ ] No [X]

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
Yes [X] No [ ]

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).
Yes [X] No [ ]

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.[ ]

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act. (Check one):

Large Accelerated Filer [X]	Accelerated Filer [ ]
Non-accelerated Filer [ ]	Smaller Reporting Company [ ]
Emerging Growth Company [ ]	

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act.[ ]

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
Yes [ ] No [X]

As of June 30, 2017, the aggregate market value of the shares of Common Stock (based upon the closing price of these shares on the New York Stock Exchange on that date) held by non-affiliates was $1,695,121,435.

At February 16, 2018, 28,751,528 shares of the registrant's Common Stock (the only class of Common Stock) were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Proxy Statement of the registrant, to be filed in connection with the 2018 Annual Meeting of Shareholders, are incorporated by reference in Part III.

NORTHWEST NATURAL GAS COMPANY

Annual Report to Securities and Exchange Commission on Form 10-K
For the Fiscal Year Ended December 31, 2017

TABLE OF CONTENTS

AFUDC	Allowance for Funds Used During Construction
AOCI / AOCL	Accumulated Other Comprehensive Income (Loss)
ASC	Accounting Standards Codification
ASU	Accounting Standards Update as issued by the FASB
Average Weather	The 25-year average of heating degree days based on temperatures established in our last Oregon general rate case
Bcf	Billion cubic feet, a volumetric measure of natural gas, where one Bcf is roughly equal to 10 million therms
CNG	Compressed Natural Gas
Core Utility Customers	Residential, commercial, and industrial customers receiving firm service from the utility
Cost of Gas	The delivered cost of natural gas sold to customers, including the cost of gas purchased or withdrawn/produced from storage inventory or reserves, gains and losses from gas commodity hedges, pipeline demand costs, seasonal demand cost balancing adjustments, regulatory gas cost deferrals and Company gas use
CPUC	California Public Utilities Commission, the entity that regulates our California gas storage business at our Gill Ranch facility with respect to rates and terms of service, among other matters
Decoupling	A billing rate mechanism, also referred to as our conservation tariff, which is designed to allow the utility to encourage industrial and small commercial customers to conserve energy while not adversely affecting its earnings due to reductions in sales volumes
Demand Cost	A component in core utility customer rates representing the cost of securing firm pipeline capacity, whether the capacity is used or not
EBITDA	Earnings before interest, taxes, depreciation and amortization, a non-GAAP financial measure
EE/CA	Engineering Evaluation / Cost Analysis
Encana	Encana Oil & Gas (USA) Inc.
Energy Corp	Northwest Energy Corporation, a wholly-owned subsidiary of NW Natural
EPA	Environmental Protection Agency
EPS	Earnings per share
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission; the entity regulating interstate storage services offered by our Mist gas storage facility as part of our gas storage segment
Firm Service	Natural gas service offered to customers under contracts or rate schedules that will not be disrupted to meet the needs of other customers
FMBs	First Mortgage Bonds
GAAP	Accounting principles generally accepted in the United States of America
General Rate Case	A periodic filing with state or federal regulators to establish billing rates for utility customers
GHG	Greenhouse gases
Gill Ranch	Gill Ranch Storage, LLC, a wholly-owned subsidiary of NWN Gas Storage
Gill Ranch Facility	Underground natural gas storage facility near Fresno, California, with 75% owned by Gill Ranch and 25% owned by PG&E
GTN	Gas Transmission Northwest, which owns a transmission pipeline serving California and the Pacific Northwest
Heating Degree Days	Units of measure reflecting temperature-sensitive consumption of natural gas, calculated by subtracting the average of a day's high and low temperatures from 65 degrees Fahrenheit
HATFA	Highway and Transportation Funding Act of 2014
IBEW	International Brotherhood of Electrical Workers Local Union No. 1245, which is also referred to as the Union formerly representing NW Natural's bargaining unit employees at Gill Ranch
Interruptible Service	Natural gas service offered to customers (usually large commercial or industrial users) under contracts or rate schedules that allow for interruptions when necessary to meet the needs of firm service customers
IRP	Integrated Resource Plan
KB	Kelso-Beaver Pipeline, of which 10% is owned by KB Pipeline Company, a subsidiary of NNG Financial
LNG	Liquefied Natural Gas, the cryogenic liquid form of natural gas. To reach a liquid form at atmospheric pressure, natural gas must be cooled to approximately negative 260 degrees Fahrenheit

MAP-21	A federal pension plan funding law called the Moving Ahead for Progress in the 21st Century Act, July 2012
Moody's	Moody's Investors Service, Inc., credit rating agency
NAV	Net Asset Value
NNG Financial	NNG Financial Corporation, a wholly-owned subsidiary of NW Natural
NOL	Net Operating Loss
NRD	Natural Resource Damages
NWN Energy	NW Natural Energy, LLC, a wholly-owned subsidiary of NW Natural
NWN Gas Reserves	NWN Gas Reserves LLC, a wholly-owned subsidiary of Northwest Energy Corporation
NWN Gas Storage	NW Natural Gas Storage, LLC, a wholly-owned subsidiary of NWN Energy
ODEQ	Oregon Department of Environmental Quality
OPEIU	Office and Professional Employees International Union Local No. 11, AFL-CIO, which is also referred to as the Union representing NW Natural's bargaining unit employees
OPUC	Public Utility Commission of Oregon; the entity that regulates our Oregon utility business with respect to rates and terms of service, among other matters; the OPUC also regulates our Mist gas storage facility's intrastate storage services
PBGC	Pension Benefit Guaranty Corporation
PG&E	Pacific Gas & Electric Company; 25% owner of the Gill Ranch Facility
PGA	Purchased Gas Adjustment, a regulatory mechanism which adjusts customer rates to reflect changes in the forecasted cost of gas and differences between forecasted and actual gas costs from the prior year
PGE	Portland General Electric; primary customer of the North Mist gas storage expansion
PHMSA	U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration
PRP	Potentially Responsible Parties
RI/FS	Remedial Investigation / Feasibility Study
ROD	Record of Decision
ROE	Return on Equity, a measure of corporate profitability, calculated as net income or loss divided by average common stock equity. Authorized ROE refers to the equity rate approved by a regulatory agency for use in determining utility revenue requirements
ROR	Rate of Return, a measure of return on utility rate base. Authorized ROR refers to the rate of return approved by a regulatory agency and is generally discussed in the context of ROE and capital structure
S&P	Standard & Poor's, a credit rating agency and division of The McGraw-Hill Companies, Inc.
Sales Service	Service provided whereby a customer purchases both natural gas commodity supply and transportation from the utility
SEC	U.S. Securities and Exchange Commission
SRRM	Site Remediation and Recovery Mechanism, a billing rate mechanism for recovering prudently incurred environmental site remediation costs allocable to Oregon through customer billings, subject to an earnings test
TAIL	TransCanada American Investments, Ltd., a 50% owner of TWH
TCJA	H.R.1; An act to provide for reconciliation pursuant to titles II and V of the concurrent resolution on the budget for fiscal year 2018, also known as the Tax Cuts and Jobs Act enacted on December 22, 2017
Therm	The basic unit of natural gas measurement, equal to one hundred thousand Btu’s
TWH	Trail West Holdings, LLC, 50% owned by NWN Energy
TWP	Trail West Pipeline, LLC, a subsidiary of TWH
TransCanada	TransCanada Pipelines Limited, owner of TAIL and GTN
Transportation Service	Service provided whereby a customer purchases natural gas directly from a supplier but pays the utility to transport the gas over its distribution system to the customer’s facility
Utility Margin	A financial measure consisting of utility operating revenues less the associated cost of gas, franchise taxes, and environmental recoveries
WARM	An Oregon billing rate mechanism applied to residential and commercial customers to adjust for temperature variances from average weather
WUTC	Washington Utilities and Transportation Commission, the entity that regulates our Washington utility business with respect to rates and terms of service, among other matters

FORWARD-LOOKING STATEMENTS

This report contains forward-looking statements within the meaning of the U.S. Private Securities Litigation Reform Act of 1995, which are subject to the safe harbors created by such Act. Forward-looking statements can be identified by words such as anticipates, assumes, intends, plans, seeks, believes, estimates, expects, and similar references to future periods. Examples of forward-looking statements include, but are not limited to, statements regarding the following:

- plans, projections and predictions;
- objectives, goals or strategies;
- assumptions, generalizations and estimates;
- ongoing continuation of past practices or patterns;
- future events or performance;
- trends;
- risks;
- timing and cyclicality;
- earnings and dividends;
- capital expenditures and allocation;
- capital or organizational structure, including restructuring as a holding company;
- climate change and our role in a low-carbon future;
- growth;
- customer rates;
- labor relations and workforce succession;
- commodity costs;
- gas reserves;
- operational performance and costs;
- energy policy, infrastructure and preferences;
- public policy approach and involvement;
- efficacy of derivatives and hedges;
- liquidity, financial positions, and planned securities issuances;
- valuations;
- project and program development, expansion, or investment;
- business development efforts, including acquisitions and integration thereof;
- pipeline capacity, demand, location, and reliability;
- adequacy of property rights and headquarter development;
- technology implementation and cybersecurity practices;
- competition;
- procurement and development of gas supplies;
- estimated expenditures;
- costs of compliance;
- credit exposures;
- rate or regulatory outcomes, recovery or refunds;
- impacts or changes of laws, rules and regulations;
- tax liabilities or refunds, including effects of tax reform;
- levels and pricing of gas storage contracts and gas storage markets;
- outcomes, timing and effects of potential claims, litigation, regulatory actions, and other administrative matters;
- projected obligations, expectations and treatment with respect to retirement plans;
- availability, adequacy, and shift in mix, of gas supplies;
- effects of new or anticipated changes in critical accounting policies or estimates;
- approval and adequacy of regulatory deferrals;
- effects and efficacy of regulatory mechanisms; and
- environmental, regulatory, litigation and insurance costs and recoveries, and timing thereof.

Forward-looking statements are based on our current expectations and assumptions regarding our business, the economy, and other future conditions. Because forward-looking statements relate to the future, they are subject to inherent uncertainties, risks, and changes in circumstances that are difficult to predict. Our actual results may differ materially from those contemplated by the forward-looking statements. We therefore caution you against relying on any of these forward-looking statements. They are neither statements of historical fact nor guarantees or assurances of future performance. Important factors that could cause actual results to differ materially from those in the forward-looking statements are discussed at Item 1A., "Risk Factors" of Part I and Item 7. and Item 7A., "Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Quantitative and Qualitative Disclosures About Market Risk", respectively, of Part II of this report.

Any forward-looking statement made by us in this report speaks only as of the date on which it is made. Factors or events that could cause our actual results to differ may emerge from time to time, and it is not possible for us to predict all of them. We undertake no obligation to publicly update any forward-looking statement, whether as a result of new information, future developments or otherwise, except as may be required by law.

NORTHWEST NATURAL GAS COMPANY
PART I

ITEM 1. BUSINESS

OVERVIEW

Northwest Natural Gas Company (NW Natural or the Company) was incorporated under the laws of Oregon in 1910. Our Company and its predecessors have supplied gas service to the public since 1859, and we have been doing business as NW Natural since 1997. We maintain operations in Oregon, Washington, and California and conduct business through NW Natural and its subsidiaries. References in this discussion to "Notes" are to the Notes to the Consolidated Financial Statements in Item 8 of this report.

We have two core businesses: our regulated local gas distribution business, referred to as the utility segment, which serves residential, commercial, and industrial customers in Oregon and southwest Washington; and our gas storage businesses, referred to as the gas storage segment, which provides storage services for utilities, gas marketers, electric generators, and large industrial users from storage facilities located in Oregon and California. In addition, we have investments and other non-utility activities we aggregate and report as other. See Note 4 for further information.

The utility business is our largest segment, while our gas storage business accounts for the majority of our remaining net income or loss. The following table reflects the allocation between segments and other as of December 31, 2017:

		Non-Utility[(1)]		
In millions	Utility	Gas Storage[(2)]	Other	Total
Assets[(3)]	$ 2,961.3	$ 59.6	$ 18.8	$ 3,039.7
Net income (loss)[(3)]	60.5	(116.2)	0.1	(55.6)

(1) We refer to our gas storage segment and other as non-utility as they are not included in our regulated gas distribution business; however, certain aspects of the gas storage segment and other may be regulated by the OPUC, WUTC, CPUC, or FERC.
(2) Our gas storage segment includes asset management services for both the utility and non-utility portion of our Mist gas storage facility.
(3) Our assets and net loss include an impairment of long-lived assets at the Gill Ranch Facility of $192.5 million and $141.5 million, respectively. See Part II, Item 7, "Application of Critical Accounting Policies and Estimates—Impairment of Long-Lived Assets."

LOCAL GAS DISTRIBUTION "UTILITY"

The utility is principally engaged in the regulated distribution of natural gas in Oregon and southwest Washington to over 735,000 customers with approximately 89% of our customers located in Oregon and 11% located in Washington. In total, we provide natural gas service to over 100 cities in 18 counties with an estimated population of 3.7 million in our service territory.

We have been allocated an exclusive service territory by the OPUC and WUTC, which includes a major portion of western Oregon, including the Portland metropolitan area, most of the Willamette Valley, the Coastal area from Astoria to Coos Bay, and portions of Washington along the Columbia River. Portland serves as one of the largest international ports on the West Coast and is a key distribution center due to its comprehensive transportation system of ocean and river shipping, transcontinental railways and highways, and an international airport. Major businesses located in our service territory include retail, manufacturing, and high-technology industries.

Customers

We serve residential, commercial, and industrial customers with no individual customer or industry accounting for more than 10% of our utility revenues. On an annual basis, residential and commercial customers typically account for 55% to 60% of our utility's total volumes delivered and 90% of our utility's margin. Industrial customers largely account for the remaining volumes and utility margin.

The following table presents summary customer information as of December 31, 2017:

	Number of Customers	% of Volumes	% of Utility Margin [(1)]
Residential	668,803	38%	63%
Commercial	68,050	22%	28%
Industrial	1,021	40%	8%
Other	N/A	N/A	1%
Total	737,874	100%	100%

(1) Utility margin is also affected by other items, including miscellaneous services, gains or losses from our gas cost incentive sharing mechanism, and other service fees.

Generally, residential and commercial customers purchase both their natural gas commodity (gas sales) and natural gas delivery services (transportation services) from the utility. Industrial customers also purchase transportation services from the utility, but may buy the gas commodity either from the utility or directly from a third-party gas marketer or supplier. Our gas commodity cost is primarily a pass-through cost to customers; therefore, our profit margins are not materially affected by an industrial customer's decision to purchase gas from us or from third parties. Industrial and large commercial customers may also select between firm and interruptible service levels, with firm services generally providing higher profit margins compared to interruptible services.

To help manage gas supplies, our industrial tariffs are designed to provide some certainty regarding industrial customers' volumes by requiring an annual service election, special charges for changes between elections, and in some cases, a minimum or maximum volume requirement before changing options.

Customer growth rates for natural gas utilities in the Pacific Northwest historically have been among the highest in the nation due to lower market saturation as natural gas became widely available as a residential heating source after other fuel options. We estimate natural gas was in approximately 63% of single-family residential homes in both 2017 and 2016 using our in-house system mapping technology. Customer growth in our region comes from the following main sources: single-family housing, both new construction and conversions; multifamily housing new construction; and commercial buildings, both new construction and conversions. Single-family new construction has consistently been our strongest performing source of growth. Continued customer growth is closely tied to the comparative price of natural gas to electricity and fuel oil and the health of the Portland, Oregon and Vancouver, Washington economies. We believe there is potential for continued growth as natural gas is a preferred energy source due to its affordable, reliable, and clean qualities.

Competitive Conditions

In our service areas, we have no direct competition from other natural gas distributors, but we compete with other forms of energy in each customer class. This competition among energy suppliers is based on price, efficiency, reliability, performance, preference, market conditions, technology, federal, state, and local energy policy, and environmental impacts.

For residential and small to mid-size commercial customers, we compete primarily with providers of electricity, fuel oil, and propane.

In the industrial and large commercial markets, we compete with all forms of energy, including competition from wholesale natural gas marketers. In addition, large industrial customers could bypass our local gas distribution system by installing their own direct pipeline connection to the interstate pipeline system. We have designed custom transportation service agreements with several of our largest industrial customers to provide transportation service rates that are competitive with the customer's costs of installing their own pipeline; these agreements generally prohibit bypass. Due to the cost pressures confronting a number of our largest customers competing in global markets, bypass continues to be a competitive threat. Although we do not expect a significant number of our large customers to bypass our system in the foreseeable future, we could experience deterioration of utility margin if customers bypass or switch over to custom contracts with lower profit margins.

Seasonality of Business

Our utility business is seasonal in nature due to higher gas usage by residential and commercial customers during the cold winter heating months. Our other categories of customers experience seasonality in their usage but to a lesser extent.

Regulation and Rates

The utility is subject to regulation by the OPUC, WUTC, and FERC. These regulatory agencies authorize rates and allow recovery mechanisms to provide our utility the opportunity to recover prudently incurred capital and operating costs from customers, while also earning a reasonable return on investment for investors. In addition, the OPUC and WUTC also regulate the system of accounts and issuance of securities by our utility.

We file general rate cases and rate tariff requests periodically with the commissions to establish approved rates, an authorized ROE, an overall rate of return on rate base (ROR), an authorized utility capital structure, and other revenue/cost deferral and recovery mechanisms.

In addition, under our Mist interstate storage certificate with FERC, the utility is required to file either a petition for rate approval or a cost and revenue study every five years to change or justify maintaining the existing rates for the interstate storage service.

For further discussion on our most recent general rate cases, see Part II, Item 7, "Results of Operations—Regulatory Matters—*Regulation and Rates*".

Gas Supply

The utility strives to secure sufficient, reliable supplies of natural gas to meet the needs of customers at the lowest reasonable cost, while maintaining price stability and managing gas purchase costs prudently. This is accomplished through a comprehensive strategy focused on the following items:

- **Reliability** - ensuring gas resource portfolios are sufficient to satisfy customer requirements under extreme cold weather conditions;
- **Diverse Supply** - providing diversity of supply sources;
- **Diverse Contracts** - maintaining a variety of contract durations, types, and counterparties; and
- **Cost Management and Recovery** - employing prudent gas cost management strategies.

Reliability

The effectiveness of our gas distribution system ultimately rests on whether we provide reliable service to our core utility customers. To ensure our effectiveness, we develop a composite design year, including a seven-day design peak event based on the most severe cold weather experienced during the last 30 years in our service territory.

Our projected maximum design day firm utility customer sendout is approximately 9.7 million therms. Of this total, we are currently capable of meeting about 57% of our maximum design day requirements with gas from storage located within or adjacent to our service territory, while the remaining supply requirements would come from gas purchases under firm gas purchase contracts and recall agreements.

To supplement near-term natural gas supplies, we can segment transportation capacity during the heating seasons, if needed. Pipeline segmentation is a natural gas transportation mechanism under which a shipper can leverage its firm pipeline transportation capacity by separating it into multiple segments with alternate delivery routes. The reliability of service on these alternate routes will vary depending on the constraints of the pipeline system. For those segments with acceptable reliability, segmentation provides a shipper with increased flexibility and potential cost savings compared to traditional pipeline service. During the 2016-2017 and 2017-2018 heating seasons, we segmented and relied on approximately 0.6 million therms per day of our firm pipeline transportation capacity that flowed from Stanfield, Oregon to various points south of Molalla, Oregon.

We believe our gas supplies would be sufficient to meet existing firm customer demand if we were to experience maximum design day weather conditions. We will continue to evaluate and update our forecasted requirements and incorporate changes in our IRP process.

The following table shows the sources of supply projected to be used to satisfy the design day sendout for the 2017-2018 winter heating season:

Therms in millions	Therms	Percent
Sources of utility supply:		
Firm supply purchases	3.4	34%
Mist underground storage (utility only)	3.1	32
Company-owned LNG storage	1.9	19
Off-system storage contract	0.5	5
Pipeline segmentation capacity	0.6	6
Recall agreements	0.4	4
Total	9.9	100%

The OPUC and WUTC have IRP processes in which utilities define different growth scenarios and corresponding resource acquisition strategies in an effort to evaluate supply and demand resource requirements, consider uncertainties in the planning process and the need for flexibility to respond to changes, and establish a plan for providing reliable service at the least cost.

We file a full IRP biennially for Oregon and Washington with the OPUC and the WUTC, respectively, and file updates between filings. The OPUC acknowledges the Company's action plan; whereas the WUTC provides notice that our IRP has met the requirements of the Washington Administrative Code. OPUC acknowledgment of the IRP does not constitute ratemaking approval of any specific resource acquisition strategy or expenditure. However, the Commissioners generally indicate that they would give considerable weight in prudence reviews to utility actions consistent with acknowledged plans. The WUTC has indicated the IRP process is one factor it will consider in a prudence review. For additional information see Part II, Item 7, "Results of Operations—*Regulatory Matters*".

Diversity of Supply Sources

We purchase our gas supplies primarily from the Alberta and British Columbia areas of Canada and multiple receipt points in the U.S. Rocky Mountains to protect against regional supply disruptions and to take advantage of price differentials. For 2017, 59% of our gas supply came from Canada, with the balance primarily coming from the U.S. Rocky Mountain region. We believe gas supplies available in the western United States and Canada are adequate to serve our core utility requirements for the foreseeable future. We continue to evaluate the long-term supply mix based on projections of gas production and pricing in the U.S. Rocky Mountain region as well as other regions in North America; however, we believe the cost of natural gas coming from western Canada and the U.S. Rocky Mountain region will continue to track with broader U.S. market pricing. Additionally, the extraction of shale gas has increased the availability of gas supplies throughout North America for the foreseeable future.

We supplement our firm gas supply purchases with gas withdrawals from gas storage facilities, including underground reservoirs and LNG storage facilities. Storage facilities are generally injected with natural gas during the off-peak months in the spring and summer and the gas is withdrawn for use during peak demand months in the winter.

The following table presents the storage facilities available for our utility supply:

	Maximum Daily Deliverability *(therms in millions)*	Designed Storage Capacity (Bcf)
Gas Storage Facilities		
Owned Facility		
Mist, Oregon[1]	3.1	10.6
Contracted Facilities		
Jackson Prairie, Washington[2]	0.5	1.1
Alberta, Canada[3]	0.3	1.5
LNG Facilities		
Owned Facilities		
Newport, Oregon	0.6	1.0
Portland, Oregon	1.3	0.6
Total	5.8	14.8

(1) The Mist gas storage facility has a total maximum daily deliverability of 5.4 million therms and a total designed storage capacity of about 16 Bcf, of which 3.1 million therms of daily deliverability and 10.6 Bcf of storage capacity are reserved for core utility customers.

(2) The storage facility is located near Chehalis, Washington and is contracted from Northwest Pipeline, a subsidiary of The Williams Companies.

(3) This resource does not add to our total peak day capacity, but mitigates price risks as it displaces equivalent volumes of heating season spot purchases.

The Mist facility is used for both utility and non-utility purposes. Under our regulatory agreements with the OPUC and WUTC, non-utility gas storage at Mist can be developed in advance of core utility customer needs but is subject to recall by the utility when needed to serve utility customers as their demand increases. In 2017, the utility did not recall additional deliverability or associated storage capacity from the non-utility business to serve core utility customer needs.

In addition, we have the ability to recall pipeline capacity and supply resources from certain customers if needed to meet high demand requirements.

Diverse Contract Durations and Types

We have a diverse portfolio of short-, medium-, and long-term firm gas supply contracts and a variety of contract types including firm and interruptible supplies as well as supplemental supplies from gas storage facilities.

Our portfolio of firm gas supply contracts typically includes the following gas purchase contracts: year-round and winter-only baseload supplies; seasonal supply with an option to call on additional daily supplies during the winter heating season; and daily or monthly spot purchases.

During 2017, we purchased a total of 857 million therms under contracts with durations outlined in the chart below:

Contract Duration (primary term)	Percent of Purchases
Long-term (one year or longer)	26%
Short-term (more than one month, less than one year)	23
Spot (one month or less)	51
Total	100%

We renew or replace gas supply contracts as they expire. During 2017, no individual supplier provided over 10% of our gas supply requirements.

Gas Cost Management

The cost of gas sold to utility customers primarily consists of the following items, which are included in annual PGA rates: gas purchases from suppliers; charges from pipeline companies to transport gas to our distribution system; gas storage costs; gas reserves contracts; and gas commodity derivative contracts.

We employ a number of strategies to mitigate the cost of gas sold to utility customers. Our primary strategies for managing gas commodity price risk include:

- negotiating fixed prices directly with gas suppliers;
- negotiating financial derivative contracts that: (1) effectively convert floating index prices in physical gas supply contracts to fixed prices (referred to as commodity price swaps); or (2) effectively set a ceiling or floor price, or both, on floating index priced physical supply contracts (referred to as commodity price options such as calls, puts, and collars). See Part II, Item 7A, "Quantitative and Qualitative Disclosures About Market Risk—Credit Risk—*Credit Exposure to Financial Derivative Counterparties*";
- buying physical gas supplies at a set price and injecting the gas into storage for price stability and to minimize pipeline capacity demand costs; and
- investing in gas reserves for longer term price stability. See Note 11 for additional information about our gas reserves.

We also contract with an independent energy marketing company to capture opportunities regarding our storage and pipeline capacity when those assets are not serving the needs of our core utility customers. Our asset management activities provide opportunities for cost of gas savings for our customers and incremental revenues for our shareholders through a regulatory incentive-sharing mechanism. These activities are included in our gas storage segment.

Gas Cost Recovery

Mechanisms for gas cost recovery are designed to be fair and reasonable, with an appropriate balance between the interests of our customers and shareholders. In general, utility rates are designed to recover the costs of, but not to earn a return on, the gas commodity sold. We minimize risks associated with gas cost recovery by resetting customer rates annually through the PGA and aligning customer and shareholder interests through the use of sharing, weather normalization, and conservation mechanisms in Oregon. See Part II, Item 7, "Results of Operations—*Regulatory Matters*" and "Results of Operations—Business Segments—Local Gas Distribution Utility Operations—*Cost of Gas*."

Transportation of Gas Supplies

Our local gas distribution system is reliant on a single, bi-directional interstate transmission pipeline to bring gas supplies into our distribution system. Although we are dependent on a single pipeline, the pipeline's gas flows into the Portland metropolitan market from two directions: (1) the north, which brings supplies from the British Columbia and Alberta supply basins; and (2) the east, which brings supplies from Alberta as well as the U.S. Rocky Mountain supply basins.

We incur monthly demand charges related to our firm pipeline transportation contracts. These contracts are multi-year contracts with expirations ranging from 2018 to 2060. Our largest pipeline agreements are with Northwest Pipeline. We actively work with Northwest Pipeline and others to renew contracts in advance of expiration to ensure gas transportation capacity is sufficient to meet our utility needs.

Rates for interstate pipeline transportation services are established by FERC within the U.S. and by Canadian authorities for services on Canadian pipelines.

As mentioned above, our service territory is dependent on a single pipeline for its natural gas supply. Although supply has not been disrupted in the recent past, pipeline replacement projects and long-term projected natural gas demand in our region underscore the need for pipeline transportation diversity. In addition, there are potential industrial projects in the region, which could increase the demand for natural gas and the need for additional pipeline capacity and pipeline diversity.

Currently, there are various interstate pipeline projects proposed, including the Trail West pipeline in which we have an interest, that could meet the forecasted demand for us and the region. However, the location of any future pipeline project will likely depend on the location of committed industrial projects. We will continue to evaluate and closely monitor the currently prospected projects to determine the best option for our customers. We have an equity investment in Trail West Holdings, LLC (TWH) that is developing plans to build the Trail West pipeline. This pipeline would connect TransCanada Pipelines Limited's (TransCanada) Gas Transmission Northwest (GTN) interstate transmission line to our local gas distribution system. If constructed, this pipeline would provide another transportation path for gas purchases from Alberta and the U.S. Rocky Mountains in addition to the one that currently moves gas through the Northwest Pipeline system.

Gas Distribution

The primary goals of our gas distribution operations are safety and reliability of our system, which entails building and maintaining a safe pipeline distribution system.

Safety and the protection of our employees, our customers, and the public at large are, and will remain, our top priorities. We construct, operate, and maintain our pipeline distribution system and storage operations with the goal of ensuring natural gas is delivered and stored safely, reliably, and efficiently.

NW Natural has one of the most modern distribution systems in the country with no identified cast iron pipe or bare steel main. We removed the final known bare steel from our system in 2015 and completed our cast iron pipe removal in 2000. Since the 1980s, we have taken a proactive approach to replacement programs and partnered with our Commissions on progressive regulation to further safety and reliability efforts for our distribution system. In the past, we had a cost recovery program in Oregon that encompassed our programs for bare steel replacement, transmission pipeline integrity management, and distribution pipeline integrity management. If we want to have future cost recovery programs, we would have to seek PUC approval. For discussion on current regulatory programs, see Part II, Item 7, "Results of Operations—*Regulatory Matters*".

Natural gas distribution businesses will continue to be subject to greater federal and state regulation in the future due to pipeline incidents involving other companies. Additional operating and safety regulations from the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) are currently under development. In 2016, PHMSA issued proposed regulations to update safety requirements for natural gas transmission pipelines. The final draft of these regulations is anticipated to be issued by the end of 2018, with final regulations anticipated to be issued in 2019. Current proposed regulations indicate a 15-year timeline for implementation of compliance requirements. We will continue to work diligently with industry associations as well as federal and state regulators to ensure the safety of our system and compliance with new laws and regulations. We expect the costs to our utility associated with compliance with federal, state, and local rules would be recoverable in rates.

North Mist Gas Storage Expansion Project

In Oregon, there is a need to integrate intermittent resources, such as wind and solar, into the power system with policymakers committing to the elimination of coal-fired electric generation and moving toward a 50% renewable electricity standard by 2040. New, flexible natural gas-fired electric generation facilities and associated gas storage are necessary to support the integration of renewable resources. In 2016, we began expanding our gas storage facility near Mist, Oregon to provide innovative long-term, no-notice underground gas storage service to support gas-fired electric generating facilities that are intended to facilitate the integration of more wind power into the region's electric generation mix. Natural gas storage enables generation to adjust quickly when renewable energy, such as wind and solar, rises and falls.

This expansion project will be dedicated solely to Portland General Electric (PGE), a local electric company, to support their gas-fired electric power generation facilities under an initial 30-year contract with options to extend, totaling up to an additional 50 years upon mutual agreement of the parties.

The expansion project includes a new reservoir providing up to 2.5 Bcf of available storage, an additional compressor station with design capacity of 120,000 decatherms of gas per day, no-notice service that can be drawn on rapidly, and a 13-mile pipeline to connect to PGE's gas plants at Port Westward. The expansion project is considered part of the utility segment and has an estimated cost of approximately $132 million, with a targeted in-service date of the winter of 2018-19. See additional discussion in Part II, Item 7 "Financial Condition—Cash Flows—*Investing Activities*".

When the expansion is placed into service, the investment will immediately be included in rate base under an established tariff schedule already approved by the OPUC, with revenues recognized consistent with the schedule. Billing rates will be updated annually to the current depreciable asset level and forecasted operating expenses.

GAS STORAGE

Our gas storage segment includes the following:
- the non-utility portion of the Mist gas storage facility near Mist, Oregon;
- the Gill Ranch Facility near Fresno, California; and
- asset management services provided by an independent energy marketing company.

In general, the supply of natural gas remains relatively stable over the course of a year, while the demand for natural gas typically fluctuates seasonally. Storage facilities allow customers to purchase and inject natural gas supplies during periods of low demand and withdraw these supplies for use or resale during periods of higher demand. These facilities allow us to capitalize on the imbalance of supply and demand and price volatility for natural gas.

For more information on gas storage assets and results of operations, see Note 4 and Part II, Item 7, "Financial Condition—Capital Structure—*Liquidity and Capital Resources*".

Gas Storage Facilities

The following table provides information concerning our non-utility gas storage facilities:

		Maximum	
	Designed Storage Capacity (Bcf)	Deliverability (Therms in millions/day)[3]	Injection (Therms in millions/day)[3]
Mist Storage[1]	5.4	2.3	0.8
Gill Ranch Storage[2]	15.0	4.9	2.4

(1) Approximately 5.4 Bcf of a total designed storage capacity of about 16 Bcf at Mist is currently available to our gas storage segment. The remaining 10.6 Bcf is used to provide gas storage for our local distribution business and its utility customers.
(2) Our gas storage segment share of the Gill Ranch Facility is currently 15 Bcf out of a total capacity of 20 Bcf.
(3) Our gas storage segment share of the designed daily maximum injection and deliverability rates.

In addition to the designed storage capacity described above, capacity may incrementally increase based on variations in the heat content of the stored gas. All storage capacity and daily deliverability currently developed for the gas storage segment at Mist is available for recall by the utility. In 2015, the utility recalled approximately 0.3 million therms per day of deliverabiility and 0.7 Bcf of capacity for core utility customer use. There were no recalls by the utility in 2016 and 2017.

Mist Storage Facility

The Mist storage facility began operations in 1989. It is a 16 Bcf facility with 5.4 Bcf available for use in our gas storage segment. The remaining 10.6 Bcf is used to provide gas storage for our local distribution business and its utility customers. Excluding the North Mist expansion, the facility consists of seven depleted natural gas reservoirs, 22 injection and withdrawal wells, a compressor station, dehydration and control equipment, gathering lines, and other related facilities.

SERVICES. Mist provides multi-cycle gas storage services to customers in the interstate and intrastate markets from the facility located in Columbia County, Oregon, near the town of Mist. The Mist field was initially converted to storage operations for our utility customers. Since 2001, gas storage capacity at Mist has also been made available to interstate customers by developing new incremental capacity in advance of core utility customer requirements to meet the demands for interstate storage service. These interstate storage services are offered under a limited jurisdiction blanket certificate issued by FERC. In addition, since 2005 we have offered intrastate firm storage services in Oregon under an OPUC-approved rate schedule as an optional service to eligible non-residential utility customers.

CUSTOMERS. For Mist storage services, firm service agreements with customers are entered into with terms typically ranging from 1 to 10 years. Currently, our gas storage revenues from Mist are derived primarily from firm service customers who provide energy-related services, including natural gas distribution, electric generation, and energy marketing. Four storage customers currently account for all of our existing contracted non-utility gas storage capacity at Mist, with the largest customer accounting for about half of the total capacity. These four customers have contracts expiring at various dates through 2024.

COMPETITIVE CONDITIONS. Our Mist gas storage facility benefits from limited competition from other Pacific Northwest storage facilities primarily because of its geographic location. However, competition from other storage providers in Washington and Canada, as well as competition for interstate pipeline capacity, does exist. In the future, we could face increased competition from new or expanded gas storage facilities as well as from new natural gas pipelines, marketers, and alternative energy sources.

SEASONALITY. Mist gas storage revenues generally do not follow seasonal patterns similar to those experienced by the utility because most of the storage capacity is contracted with customers for firm service, which are primarily in the form of fixed monthly reservation charges and are not affected by customer usage. However, there is seasonal variation with Mist storage capacity and deliverability usage related to customers' lower demand during the spring and summer months, which can be optimized under regulatory sharing agreements with the OPUC and WUTC. For additional discussion, see *"Asset Management"* below.

REGULATION. Our Mist facility is subject to regulation by the OPUC and WUTC. In addition, FERC has approved maximum cost-based rates under our Mist interstate storage certificate. We are required to file either a petition for rate approval or a cost and revenue study with FERC at least every five years to change or justify maintaining the existing rates for the interstate storage service. For additional regulation and rates discussion, see Part II, Item 7, "Results of Operations—*Regulatory Matters"*.

EXPANSION OPPORTUNITIES. We are currently expanding our Mist Storage facility to provide 2.5 Bcf of storage to a local electric company. For additional discussion, see "*Local Gas Distribution Company—North Mist Gas Storage Expansion Project*" above. While there are additional expansion opportunities in the Mist storage field, further development is not contemplated at this time and expansion would be based on market demand, project execution, cost effectiveness, available financing, receipt of future permits, and other rights.

Gill Ranch Storage Facility

Gill Ranch Storage, LLC (Gill Ranch), our subsidiary, has a joint project agreement with Pacific Gas and Electric Company (PG&E) governing the development and ownership of the Gill Ranch Facility, an underground natural gas storage facility near Fresno, California. Currently, Gill Ranch is the sole operator of the facility. The facility began operations in 2010 and consists of three depleted natural gas reservoirs, 12 injection and withdrawal wells, a compressor station, dehydration and control equipment, gathering lines, an electric substation, a natural gas transmission pipeline extending 27 miles from the storage field to an interconnection with the PG&E transmission system, and other related facilities. Gill Ranch owns the rights to 75%, or 15.0 Bcf, of the designed gas storage capacity at the facility.

The California gas storage market is challenged by low market prices and low market price volatility resulting from the abundant supply of natural gas to, and natural gas storage in, the region. We have substantially completed contracting for this facility for the 2018-19 gas year at pricing that was lower than expected and low relative to the pricing in our original long-term contracts which ended primarily in the 2013-14 gas storage year.

We have believed and continue to believe that we may see storage price improvements or an increase in the demand for natural gas in the future driven by a number of factors, including changes in electric generation triggered by California's renewable portfolio standards, an increase in use of alternative fuels to meet carbon emission reduction targets, growth of the California economy, growth of domestic industrial manufacturing, potential exports of liquefied natural gas from the west coast, and other favorable storage market conditions in and around California. These factors, if they were to occur, may contribute to higher summer/winter natural gas price spreads, gas price volatility, and gas storage values, but there can be no assurance that any of the foregoing will occur. To the contrary, we have not seen the rebound in storage pricing as we originally anticipated.

For the last few years, we have been diligently pursuing opportunities to increase revenues at the Gill Ranch Facility. Simultaneously, we have been conducting a strategic review of Gill Ranch and exploring all strategic alternatives. In the fourth quarter of 2017, we completed our comprehensive strategic review process, which included a sale process for our portion of the Gill Ranch Facility, and made a determination that Gill Ranch is no longer considered core to our long-term growth plans.

We will continue to pursue all strategic options for this asset, including, but not limited to, a potential sale. In the meantime, we remain committed to operating the facility to the highest safety standards. See Note 2 and Part II, Item 7 "*Application of Critical Accounting Policies and Estimates*".

SERVICES. Gill Ranch provides intrastate, multi-cycle storage services in California at market-based rates under a CPUC-approved tariff that includes firm storage service, interruptible storage service, and park and loan storage services. The Gill Ranch Facility is not currently authorized to provide interstate gas storage services.

CUSTOMERS. Customer contracts for firm storage capacity at Gill Ranch have contract terms for as long as 27 years in duration; however, the majority of the contracted capacity is shorter term in nature due to market conditions. In the near-term, we expect Gill Ranch to contract for terms ranging from one to five years. For the 2017-18 gas storage year, Gill Ranch has several storage customers, with the largest single contract accounting for approximately 13% of our storage capacity. In the near-term, we continue to expect shorter contract lengths reflecting current market prices and trends.

The California market served by Gill Ranch is larger, and has a greater diversity of prospective customers, than the Pacific Northwest market served by Mist. Therefore, we expect less sensitivity to any single customer or group of customers at Gill Ranch. Current Gill Ranch customers provide energy related services, including natural gas production, marketing, and electric generation.

COMPETITIVE CONDITIONS. The Gill Ranch Facility currently competes with a number of other storage providers, including local integrated gas companies and other independent storage providers (ISPs) in the northern California market. There are currently four ISPs authorized by the CPUC to provide storage services in California, with the Gill Ranch Facility comprising approximately 12% of the storage capacity held by ISPs. An acquisition during 2016 consolidated approximately 80% of the storage capacity authorized by the CPUC to ISPs in California.

In late 2015, a significant natural gas leak occurred at an unaffiliated southern California gas storage facility. In response to the incident, both state and federal additional regulations were developed. The California Department of Oil, Gas and Geothermal Resources (DOGGR) developed and proposed new regulations for gas storage wells that focus on implementing additional well integrity requirements. Initial draft regulations suggested that individual well risk would be the basis for testing and implementation of subsurface modifications for all wells. This would potentially allow for a multiple year timeframe to comply after the issuance of the regulations with any necessary capital expenditures completed over several years after completing the testing period. DOGGR released a new formulation of these rules on February 12, 2018. Although these rules are subject to a comment period and possible revision, these rules establish a timeframe for completion of compliance within seven years, a period much shorter than we originally anticipated. We anticipate the final version of these regulations will be finalized in 2018. In addition, PHMSA proposed new federal regulations for underground natural gas storage facilities that focus on implementing additional pipeline safety requirements of downhole facilities, including operations, maintenance, and emergency response activities regarding wells, wellbore tubing, and casing.

While the regulations are still under development, and their ultimate impact is unknown, it is likely the final PHMSA and DOGGR regulations will result in higher costs for all storage providers. As a result of the legislation and proposed regulation, the nature of, and demand for, future storage contracts, costs of operating, and market values in California could be impacted and remain uncertain at this time.

SEASONALITY. While the majority of our Gill Ranch revenues are not subject to seasonality, and although we expect much of the storage revenue at Gill Ranch to be in the form of fixed monthly demand charges, cash flows can fluctuate due to timing of asset management and other revenues. In addition, a significant portion of operating costs at Gill Ranch are subject to fluctuations based on periods when storage customers elect to inject or withdraw.

REGULATION. Gill Ranch has a tariff on file with the CPUC authorizing it to charge market-based rates for the storage services offered. For additional discussion, see Part II, Item 7, "Results of Operations–*Regulatory Matters*".

EXPANSION OPPORTUNITIES. Subject to market demand, project execution, available financing, receipt of future permits, and other rights, the Gill Ranch Facility can be expanded beyond the current combined ownership designed storage capacity of 20 Bcf without further expansion of the takeaway pipeline system. Taking these considerations into account and with certain infrastructure modifications, we currently estimate the Gill Ranch Facility could support an additional 25 Bcf of storage capacity, bringing the total storage capacity to approximately 45 Bcf, of which our current rights would give us up to an additional 7.5 Bcf or ownership of a total of approximately 22.5 Bcf. We have no plans to expand the facility.

<u>Asset Management</u>

We contract with an independent energy marketing company to provide asset management services, primarily through the use of commodity exchange agreements and pipeline capacity release transactions. The results are included in the gas storage segment, except for amounts allocated to our utility pursuant to regulatory sharing agreements involving the use of utility assets. Utility pre-tax income from third-party asset management services is subject to revenue sharing with core utility customers. For additional discussion, see Part II, Item 7, "Results of Operations—*Business Segments—Gas Storage*".

OTHER

We have non-utility investments and other business activities which are aggregated and reported as other. Other primarily consists of:

- non-utility appliance retail center operations;
- an equity method investment in TWH, a joint venture to build and operate a gas transmission pipeline in Oregon. TWH is owned 50% by NWN Energy, a wholly-owned subsidiary of NW Natural, and 50% by TransCanada American Investments Ltd., an indirect wholly-owned subsidiary of TransCanada Corporation;
- a minority interest in the Kelso-Beaver Pipeline held by our wholly-owned subsidiary NNG Financial Corporation (NNG Financial); and
- other operating and non-operating income and expenses of the parent company that are not included in utility or gas storage operations.

The pipelines referred to above are regulated by FERC. Less than 1% of our consolidated assets and consolidated net loss are related to activities in other. For summary information for these assets and results of operations, see Note 4.

We have signed agreements to purchase two privately-owned water utilities in the Pacific Northwest. If completed, we do not expect these transactions or their continued operations to have a material impact on our financial position. We expect to include financial results from these businesses in other.

ENVIRONMENTAL MATTERS

Properties and Facilities

We own, or previously owned, properties and facilities that are currently being investigated that may require environmental remediation and are subject to federal, state, and local laws and regulations related to environmental matters. These laws and regulations may require expenditures over a long time frame to address certain environmental impacts. Estimates of liabilities for environmental costs are difficult to determine with precision because of the various factors that can affect their ultimate disposition. These factors include, but are not limited to, the following:

- the complexity of the site;
- changes in environmental laws and regulations at the federal, state, and local levels;
- the number of regulatory agencies or other parties involved;
- new technology that renders previous technology obsolete, or experience with existing technology that proves ineffective;
- the ultimate selection of a particular technology;
- the level of remediation required;
- variations between the estimated and actual period of time that must be dedicated to respond to an environmentally-contaminated site; and
- the application of environmental laws that impose joint and several liabilities on all potentially responsible parties.

We have received recovery of a portion of such environmental costs through insurance proceeds and seek the remainder of such costs through customer rates, and we believe recovery of these costs is probable. In Oregon, we have a mechanism to recover expenses, subject to an earnings test and allocation rules. See Part II, Item 7, "Results of Operations—Rate Matters—Rate Mechanisms—*Environmental Costs*", Note 2, and Note 15.

Greenhouse Gas Matters

We recognize our businesses are likely to be impacted by future requirements to address greenhouse gas emissions. Future federal and/or state requirements may seek to limit emissions of greenhouse gases, including both carbon dioxide (CO_2) and methane. These potential laws and regulations may require certain activities to reduce emissions and/or increase the price paid for energy based on its carbon content.

Current federal rules require the reporting of greenhouse gas emissions. In September 2009, the Environmental Protection Agency (EPA) issued a final rule requiring the annual reporting of greenhouse gas emissions from certain industries, specified large greenhouse gas emission sources, and facilities that emit 25,000 metric tons or more of CO_2 equivalents per year. We began reporting emission information in 2011. Under this reporting rule, local gas distribution companies like NW Natural are required to report system throughput to the EPA on an annual basis. The EPA also issued additional greenhouse gas reporting regulations requiring the annual reporting of fugitive emissions from our operations.

In addition, the state of Washington's DOE enacted the Clean Air Rule (CAR) in 2016, which capped the maximum greenhouse gas emissions allowed from stationary sources, such as natural gas utilities. For gas distribution utilities, the production of emissions from usage by their customers was considered to be production of emissions attributable to the utility. In December 2017, in a Washington State Court proceeding, the Judge ruled that the Department of Ecology lacked legislative authority to regulate non-emitting sources, such as local distribution companies. The DOE has not yet indicated whether it will appeal the ruling. Currently, the Washington state legislature is considering other similar legislation.

Additionally, the Oregon legislature is currently considering various greenhouse gas reduction proposals, including cap and trade. One such bill would create a declining cap, beginning 2021, on greenhouse gas emissions emitted by a wide variety of emission sources, including electric and natural gas utilities, and would require large utilities to hold permits, or allowances, to emit greenhouse gas emissions on a per ton basis. The Oregon legislature is currently reviewing these proposals, and we expect them to review similar proposals in the future. While there is uncertainty regarding potential compliance costs and revenue sharing impacts of these and other similar proposals, we currently expect to be able to recover compliance costs in rates, and as such, do not expect this legislation to materially affect our consolidated financial position and results of operations.

The outcome of these or any additional federal and state policy developments in the area of climate change cannot be determined at this time, but these initiatives could produce a number of results including new regulations, legal actions, additional charges to fund energy efficiency activities, or other regulatory actions. The adoption and implementation of any regulations limiting emissions of greenhouse gases from our operations could require us to incur costs to reduce emissions of greenhouse gases associated with our operations, which could result in an increase in the prices we charge our customers or a decline in the demand for natural gas. On the other hand, because natural gas is a low-carbon fuel, it is also possible future carbon constraints could create additional demand for natural gas for electric generation, direct use of natural gas in homes and businesses, and as a reliable and relatively low-emission back-up fuel source for alternative energy sources. Requirements to reduce greenhouse gas emissions from the transportation sector, such as those in Oregon's clean fuel standard, could also result in additional demand for natural gas fueled vehicles.

We continue to take proactive steps to collaboratively address future greenhouse gas emission matters, including actively participating in policy development in Oregon and, at the federal level, within the American Gas Association. We engage in policy development to help drive policies that result in real and meaningful greenhouse gas emission reductions that are affordable for our customers, and identify ways to reduce greenhouse gas emissions in our own operations. We have developed a voluntary carbon savings initiative consisting of activities that fall into three broad categories: (1) reducing the carbon intensity of our product, (2) helping customers use less energy, and (3) displacing higher carbon fuels, such as replacing diesel in heavy duty vehicles. Additionally, we help our customers reduce and offset their gas use through partnership with the Energy Trust of Oregon offering efficiency programs and the Smart Energy program, which allows customers to voluntarily contribute funds to projects such as biodigesters on dairy farms that offset the greenhouse gases produced from their natural gas use.

EMPLOYEES

At December 31, 2017, our utility workforce consisted of 1,146 employees, of which 629 were members of the Office and Professional Employees International Union (OPEIU) Local No. 11, AFL-CIO, and 517 were non-union employees. Our labor agreement with members of OPEIU covers wages, benefits, and working conditions. On May 22, 2014, our union employees ratified a new labor agreement (Joint Accord) that extends to November 30, 2019, and thereafter from year to year unless either party serves notice of its intent to negotiate modifications to the collective bargaining agreement.

At December 31, 2017, our non-utility subsidiaries had a combined workforce of 14 non-union employees, of which eight had unionized as part of IBEW Local Union No. 1245 (IBEW) and were in the process of negotiating a collective bargaining agreement. In January 2018, we were notified by the majority of those represented employees that they no longer wished to be represented by IBEW as their bargaining agent. Therefore, our gas storage segment is no longer recognizing IBEW as the bargaining agent for these eight employees.

Our subsidiaries receive certain services from centralized operations at the utility, and the utility is reimbursed for those services pursuant to a Shared Services Agreement.

ADDITIONS TO INFRASTRUCTURE

We make capital expenditures in order to maintain and enhance the safety and integrity of our pipelines, gate stations, storage facilities, and related assets, to expand the reach or capacity of those assets, or improve the efficiency of our operations. We expect to make a significant level of capital expenditures for additions to utility and gas storage infrastructure over the next five years, reflecting continued investments in customer growth, distribution system improvements, technology, and an expansion at our North Mist gas storage facility.

For the five-year period from 2018 to 2022, capital expenditures are estimated to be between $750 and $850 million.

Included in the five year period, 2018 utility capital expenditures are estimated to be between $190 and $220 million, including $20 to $30 million to complete the construction of our North Mist gas storage facility expansion. We expect to invest less than $5 million in non-utility capital investments for gas storage and other activities in 2018. Additional investments in our infrastructure during and after 2018 will depend largely on additional regulations and expansion opportunities. See additional discussion in Part II, Item 7 "Financial Condition—Cash Flows—*Investing Activities*".

EXECUTIVE OFFICERS OF THE REGISTRANT

For information concerning our executive officers, see Part III, Item 10.

AVAILABLE INFORMATION

We file annual, quarterly and current reports and other information with the Securities and Exchange Commission (SEC). Reports, proxy statements, and other information filed by us can be read, copied, and requested through the SEC by mail at U.S. Securities and Exchange Commission, 100 F Street, N.E., Washington, D.C. 20549, or online at its website (http://www.sec.gov). You can obtain information about access to the Public Reference Room and how to access or request records by calling the SEC at 1-800-SEC-0330. The SEC website contains reports, proxy and information statements, and other information we file electronically. In addition, we make available on our website (http://www.nwnatural.com), our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) and proxy materials filed under Section 14 of the Securities Exchange Act of 1934, as amended (Exchange Act), as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. We have included our website address as an inactive textual reference only. Information contained on our website is not incorporated by reference into this annual report on Form 10-K.

We have adopted a Code of Ethics for all employees, officers, and directors that is available on our website. We intend to disclose revisions and amendments to, and any waivers from, the Code of Ethics for officers and directors on our website. Our Corporate Governance Standards, Director Independence Standards, charters of each of the committees of the Board of Directors, and additional information about the Company are also available at the website. Copies of these documents may be requested, at no cost, by writing or calling Shareholder Services, NW Natural, One Pacific Square, 220 N.W. Second Avenue, Portland, Oregon 97209, telephone 503-226-4211 ext. 2402.

ITEM 1A. RISK FACTORS

Our business and financial results are subject to a number of risks and uncertainties, many of which are not within our control, which could adversely affect our business, financial condition, and results of operations. Additional risks and uncertainties that are not currently known to the Company or that are not currently believed by the Company to be material may also harm the Company's business, financial condition, and results of operations. When considering any investment in our securities, investors should carefully consider the following information, as well as information contained in the caption "Forward-Looking Statements", Item 7A, and other documents we file with the SEC. This list is not exhaustive and the order of presentation does not reflect management's determination of priority or likelihood. Additionally, our listing of risk factors that primarily affects one of our business segments does not mean that such risk factor is inapplicable to our other business segments.

Risks Related to our Business Generally

REGULATORY RISK. *Regulation of our businesses, including changes in the regulatory environment, failure of regulatory authorities to approve rates which provide for timely recovery of our costs and an adequate return on invested capital, or an unfavorable outcome in regulatory proceedings may adversely impact our financial condition and results of operations.*

The OPUC and WUTC have general regulatory authority over our utility business in Oregon and Washington, respectively, including the rates charged to customers, authorized rates of return on rate base, including ROE, the amounts and types of securities we may issue, services we provide and the manner in which we provide them, the nature of investments we make, actions investors may take with respect to our company, and deferral and recovery of various expenses, including, but not limited to, pipeline replacement, environmental remediation costs, commodity hedging expense, transactions with affiliated interests, weather adjustment mechanisms and other matters. Similarly, in our gas storage businesses FERC has regulatory authority over interstate storage services, the CPUC has regulatory authority over our Gill Ranch storage operations, and the WUTC and OPUC have regulatory authority over our Mist storage operations. Additionally, expansion of our business, including into water or other sectors, could result in regulation by other regulatory authorities.

The prices the OPUC and WUTC allow us to charge for retail service, and the maximum FERC-approved rates FERC authorizes us to charge for interstate storage and related transportation services, are the most significant factors affecting our financial position, results of operations and liquidity. The OPUC and WUTC have the authority to disallow recovery of costs they find imprudently incurred or otherwise disallowed. Additionally, the rates allowed by the FERC may be insufficient for recovery of costs incurred. We expect to continue to make expenditures to expand, improve and operate our utility distribution and gas storage systems. Regulators can find such expansions or improvements of expenditures were not prudently incurred, and deny recovery. Additionally, while the OPUC and WUTC have established an authorized rate of return for our utility through the ratemaking process, the regulatory process does not provide assurance that we will be able to achieve the earnings level authorized. Moreover, in the normal course of business we may place assets in service or incur higher than expected levels of operating expense before rate cases can be filed to recover those costs—this is commonly referred to as regulatory lag. The failure of any regulatory commission to approve requested rate increases on a timely basis to recover increased costs or to allow an adequate return could adversely impact our financial condition and results of operations.

As a regulated utility, we frequently have dockets open with our regulators. The regulatory proceedings for these dockets typically involve multiple parties, including governmental agencies, consumer advocacy groups, and other third parties. Each party has differing concerns, but all generally have the common objective of limiting amounts included in rates. We cannot predict the timing or outcome of these deferred proceedings or the effects of those outcomes on our results of operations and financial condition.

ENVIRONMENTAL LIABILITY RISK. *Certain of our properties and facilities may pose environmental risks requiring remediation, the costs of which are difficult to estimate and which could adversely affect our financial condition, results of operations, and cash flows.*

We own, or previously owned, properties that require environmental remediation or other action. We accrue all material loss contingencies relating to these properties. A regulatory asset at the utility has been recorded for estimated costs pursuant to a Deferral Order from the OPUC and WUTC. In addition to maintaining regulatory deferrals, we settled with most of our historical liability insurers for only a portion of the costs we have incurred to date and expect to incur in the future. To the extent amounts we recovered from insurance are inadequate or we are unable to recover these deferred costs in utility customer rates, we would be required to reduce our regulatory assets which would result in a charge to current year earnings. In addition, in Oregon, the OPUC approved the SRRM, which limits recovery of our deferred amounts to those amounts which satisfy an annual prudence review and earnings test that requires the Company to contribute additional amounts toward environmental remediation costs above approximately $10 million in years in which the Company earns above its authorized Return on Equity (ROE). To the extent the Company earns more than its authorized ROE in a year, the Company would be required to cover environmental expenses greater than the $10 million with those earnings that exceed its authorized ROE. In addition, the OPUC ordered a review of the SRRM in 2018 or when we obtain greater certainty of environmental costs, whichever occurs first. These ongoing prudence reviews, the earnings test, or the three-year review could reduce the amounts we are allowed to recover, and could adversely affect our financial condition, results of operations and cash flows.

Moreover, we may have disputes with regulators and other parties as to the severity of particular environmental matters, what remediation efforts are appropriate, and the portion of the costs we should bear. We cannot predict with certainty the amount or timing of future expenditures related to environmental investigation, remediation or other action, the portions of these costs allocable to us, or disputes or litigation arising in relation thereto.

Our liability estimates are based on current remediation technology, industry experience gained at similar sites, an assessment of our probable level of responsibility, and the financial condition of other potentially responsible parties. However, it is difficult to estimate such costs due to uncertainties surrounding the course of environmental remediation, the preliminary nature of certain of our site investigations, and the application of environmental laws that impose joint and several liabilities on all potentially responsible parties. These uncertainties and disputes arising therefrom could lead to further adversarial administrative proceedings or litigation, with associated costs and uncertain outcomes, all of which could adversely affect our financial condition, results of operations and cash flows.

ENVIRONMENTAL REGULATION COMPLIANCE RISK. *We are subject to environmental regulations for our ongoing operations, compliance with which could adversely affect our operations or financial results.*

We are subject to laws, regulations and other legal requirements enacted or adopted by federal, state and local governmental authorities relating to protection of the environment, including those legal requirements that govern discharges of substances into the air and water, the management and disposal of hazardous substances and waste, groundwater quality and availability, plant and wildlife protection, and other aspects of environmental regulation. For example, we are subject to reporting requirements to the Environmental Protection Agency and the Oregon Department of Environmental Quality regarding greenhouse gas emissions. Similarly, there are current legislative efforts in Oregon and Washington to cap or otherwise restrict the maximum GHGs an entity may emit without reduction efforts or other undertakings. These and other current and future additional environmental regulations could result in increased compliance costs or additional operating restrictions, which may or may not be recoverable in customer rates or through insurance. If these costs are not recoverable, they could have an adverse effect on our financial condition and results of operations.

GLOBAL CLIMATE CHANGE RISK. *Future legislation to address global climate change may expose us to regulatory and financial risk. Additionally, our business may be subject to physical risks associated with climate change, all of which could adversely affect our financial condition, results of operations and cash flows.*

There are a number of international, federal and state legislative and regulatory initiatives being proposed and adopted in an attempt to measure, control or limit the effects of global warming and climate change, including greenhouse gas emissions such as carbon dioxide and methane. Such current or future legislation or regulation could impose on us operational requirements, additional charges to fund energy efficiency initiatives, or levy a tax based on carbon content. Such initiatives could result in us incurring additional costs to comply with the imposed restrictions, provide a cost advantage to energy sources other than natural gas, reduce demand for natural gas, impose costs or restrictions on end users of natural gas, impact the prices we charge our customers, impose increased costs on us associated with the adoption of new infrastructure and technology to respond to such requirements, and may impact cultural perception of our service or products negatively, diminishing the value of our brand, all of which could adversely affect our business practices, financial condition and results of operations.

Climate change may cause physical risks, including an increase in sea level, intensified storms, water scarcity and changes in weather conditions, such as changes in precipitation, average temperatures and extreme wind or other climate conditions. A significant portion of the nation’s gas infrastructure is located in areas susceptible to storm damage that could be aggravated by wetland and barrier island erosion, which could give rise to gas supply interruptions and price spikes.

These and other physical changes could result in disruptions to natural gas production and transportation systems potentially increasing the cost of gas and affecting our ability to procure gas to meet our customer demand. These changes could also affect our distribution systems resulting in increased maintenance and capital costs, disruption of service, regulatory actions and lower customer satisfaction. Additionally, to the extent that climate change adversely impacts the economic health or weather conditions of our service territory directly, it could adversely impact customer demand or our customers' ability to pay. Such physical risks could have an adverse effect on our financial condition, results of operations, and cash flows.

STRATEGIC TRANSACTION RISK. *Our ability to successfully complete strategic transactions, including merger, acquisition, divestiture, joint venture, business development projects or other strategic transactions is subject to significant risks, including the risk that required regulatory or governmental approvals may not be obtained, risks relating to unknown or undisclosed problems or liabilities, and the risk that for these or other reasons, we may be unable to achieve some or all of the benefits that we anticipate from such transactions which could adversely affect our financial condition, results of operations, and cash flows.*

From time to time, we have pursued and may continue to pursue strategic transactions including merger, acquisition, divestiture, joint venture, business development projects or other strategic transactions. Any such transactions involve substantial risks, including the following:

- acquired businesses or assets may not produce revenues, earnings or cash flow at anticipated levels;
- acquired businesses or assets could have, or supply, environmental, permitting, or other problems for which contractual protections prove inadequate;
- we may experience difficulties in integration or operation costs of new businesses;
- we may assume liabilities which were not disclosed to us, that exceed our estimates, or for which our rights to indemnification from the seller are limited;

- we may be unable to obtain the necessary regulatory or governmental approvals to close a transaction, such approvals may be granted subject to terms that are unacceptable to us, or we may be unable to achieve anticipated regulatory treatment of any such transaction, or such benefits may be delayed or not occur at all;
- we may agree to sell assets for a price that is less than the book value of those assets.

One of more of these conditions could affect our financial condition, results of operations, and cash flows.

BUSINESS DEVELOPMENT RISK. *Our business development projects may encounter unanticipated obstacles, costs, changes or delays that could result in a project becoming impaired, which could negatively impact our financial condition, results of operations and cash flows.*

Business development projects involve many risks. We are currently engaged in several business development projects, including, but not limited to, the early planning and development stages for a regional pipeline in Oregon, and an expansion of our gas storage facility at Mist. We may also engage in other business development projects such as investment in additional long-term gas reserves, CNG refueling stations, or projects in the water sector. These projects may not be successful. Additionally, we may not be able to obtain required governmental permits and approvals to complete our projects in a cost-efficient or timely manner potentially resulting in delays or abandonment of the projects. We could also experience startup and construction delays, construction cost overruns, disputes with contractors, inability to negotiate acceptable agreements such as rights-of-way, easements, construction, gas supply or other material contracts, changes in customer demand or commitment, public opposition to projects, changes in market prices, and operating cost increases. Additionally, we may be unable to finance our business development projects at acceptable interest rates or within a scheduled time frame necessary for completing the project. One or more of these events could result in the project becoming impaired, and such impairment could have an adverse effect on our financial condition and results of operations.

JOINT PARTNER RISK. *Investing in business development projects through partnerships, joint ventures or other business arrangements affects our ability to manage certain risks and could adversely impact our financial condition, results of operations and cash flows.*

We use joint ventures and other business arrangements to manage and diversify the risks of certain utility and non-utility development projects, including our Trail West pipeline, Gill Ranch storage and our gas reserves agreements. We may acquire or develop part-ownership interests in other projects in the future, including but not limited to, in the water sector. Under these arrangements, we may not be able to fully direct the management and policies of the business relationships, and other participants in those relationships may take action contrary to our interests including making operational decisions that could affect our costs and liabilities. In addition, other participants may withdraw from the project, divest important assets, become financially distressed or bankrupt, or have economic or other business interests or goals that are inconsistent with ours.

For example, our gas reserves arrangements, which operate as a hedge backed by physical gas supplies, involve a number of risks. These risks include gas production that is significantly less than the expected volumes, or no gas volumes; operating costs that are higher than expected; changes in our consolidated tax position or tax laws that could affect our ability to take, or timing of, certain tax benefits that impact the financial outcome of this transaction; inherent risks of gas production, including disruption to operations or complete shut-in of the field; and a participant in one of these business arrangements acting contrary to our interests. In addition, while the cost of the original gas reserves venture is currently included in customer rates and additional wells under that arrangement are recovered at a specific cost, the occurrence of one or more of these risks, could affect our ability to recover this hedge in rates. Further, any new gas reserves arrangements have not been approved for inclusion in rates, and our regulators may ultimately determine to not include all or a portion of future transactions in rates. The realization of any of these situations could adversely impact the project as well as our financial condition, results of operations and cash flows.

OPERATING RISK. *Transporting and storing natural gas involves numerous risks that may result in accidents and other operating risks and costs, some or all of which may not be fully covered by insurance, and which could adversely affect our financial condition, results of operations and cash flows.*

Our operations are subject to all of the risks and hazards inherent in the businesses of local gas distribution and storage, including:

- earthquakes, floods, storms, landslides and other adverse weather conditions and hazards;
- leaks or other losses of natural gas or other chemicals or compounds as a result of the malfunction of equipment or facilities;
- damages from third parties, including construction, farm and utility equipment or other surface users;
- operator errors;
- negative performance by our storage reservoirs that could cause us to fail to meet expected or forecasted operational levels or contractual commitments to our customers;
- problems maintaining, or the malfunction of, pipelines, wellbores and related equipment and facilities that form a part of the infrastructure that is critical to the operation of our gas distribution and storage facilities;
- collapse of underground storage caverns;
- operating costs that are substantially higher than expected;
- migration of natural gas through faults in the rock or to some area of the reservoir where existing wells cannot drain the gas effectively resulting in loss of the gas;
- blowouts (uncontrolled escapes of gas from a pipeline or well) or other accidents, fires and explosions; and
- risks and hazards inherent in the drilling operations associated with the development of the gas storage facilities and/or wells.

These risks could result in personal injury or loss of human life, damage to and destruction of property and equipment, pollution or other environmental damage, breaches of our contractual commitments, and may result in curtailment or suspension of our operations, which in turn could lead to significant costs and lost revenues. Further, because our pipeline, storage and distribution facilities are in or near populated areas, including residential areas, commercial business centers, and industrial sites, any loss of human life or adverse financial outcomes resulting from such events could be significant. Additionally, we may not be able to maintain the level or types of insurance we desire, and the insurance coverage we do obtain may contain large deductibles or fail to cover certain hazards or cover all potential losses. The occurrence of any operating risks not covered by insurance could adversely affect our financial condition, results of operations and cash flows.

BUSINESS CONTINUITY RISK. *We may be adversely impacted by local or national disasters, pandemic illness, terrorist activities, including cyber-attacks or data breaches, and other extreme events to which we may not be able to promptly respond.*

Local or national disasters, pandemic illness, terrorist activities, including cyber-attacks and data breaches, and other extreme events are a threat to our assets and operations. Companies in critical infrastructure industries may face a heightened risk due to exposure to acts of terrorism, including physical and security breaches of our information technology infrastructure in the form of cyber-attacks. These attacks could target or impact our technology or mechanical systems that operate our distribution, transmission or storage facilities and result in a disruption in our operations, damage to our system and inability to meet customer requirements. In addition, the threat of terrorist activities could lead to increased economic instability and volatility in the price of natural gas or other necessary commodities that could affect our operations. Threatened or actual national disasters or terrorist activities may also disrupt capital or bank markets and our ability to raise capital or obtain debt financing, or impact our suppliers or our customers directly. Local disaster or pandemic illness could result in part of our workforce being unable to operate or maintain our infrastructure or perform other tasks necessary to conduct our business. A slow or inadequate response to events may have an adverse impact on operations and earnings. We may not be able to maintain sufficient insurance to cover all risks associated with local and national disasters, pandemic illness, terrorist activities and other events. Additionally, large scale natural disasters or terrorist attacks could destabilize the insurance industry making insurance we do have unavailable, which could increase the risk that an event could adversely affect our operations or financial results.

HOLDING COMPANY DIVIDEND RISK. *If we were to reorganize as a holding company, the holding company would depend on its operating subsidiaries to meet financial obligations and the ability of the holding company to pay dividends on its common stock would be dependent on the receipt of dividends and other payments from its subsidiaries.*

If we were to implement a holding company structure, NW Natural common stock would be converted or exchanged into shares of a holding company with the only significant assets being the stock of its operating subsidiaries, including NW Natural. NW Natural and its current subsidiaries, which would become NW Holding's direct and indirect subsidiaries, are separate and distinct legal entities, managed by their own boards of directors, and, as is currently the case, would have no obligation to pay any amounts to their respective shareholders, whether through dividends, loans or other payments. The ability of these companies to pay dividends or make other distributions on their common stock is now, and would continue to be, subject to, among other things: their results of operations, net income, cash flows and financial condition, as well as the success of their business strategies and general economic and competitive conditions; the prior rights of holders of existing and future debt securities and any future preferred stock issued by those companies; and any applicable legal restrictions.

In addition, the ability of the holding company's subsidiaries to pay upstream dividends and make other distributions would be subject to applicable state law and regulatory restrictions. Under the OPUC and WUTC regulatory approvals for the holding company formation, if NW Natural ceases to comply with credit and capital structure requirements approved by the OPUC and WUTC, it will not, with limited exceptions, be permitted to pay dividends to the holding company. Under the OPUC and WUTC orders authorizing the Company to form a holding company, NW Natural may not pay dividends or make distributions to the holding company if NW Natural's credit ratings and common equity levels fall below specified ratings and levels. If NW Natural's long-term secured credit ratings are below A- for S&P and A3 for Moody's, dividends may be issued so long as NW Natural's common equity is 45% or above. If NW Natural's long-term secured credit ratings are below BBB for S&P and Baa2 for Moody's, dividends may be issued so long as NW Natural's common equity is 46% or above. Dividends may not be issued if NW Natural's long-term secured credit ratings fall to BB+ or below for S&P or Ba1 or below for Moody's, or if NW Natural's common equity is below 44%. In each case, with the common equity level to be determined on a preceding or projected 13-month basis.

HOLDING COMPANY PRIORITY RISK. *If a holding company structure is completed, the holding company's ability to pay dividends on its common stock would be subject to the prior rights of holders of its indebtedness and preferred stock, if any.*

If we were to form a holding company, it may from time to time issue debt securities and preferred stock, as well as additional shares of holding company common stock, in order to make capital contributions to one or more of its subsidiaries or for other reasons, although NW Natural would likely continue to issue its own debt securities and may issue preferred stock. The holding company could also guarantee indebtedness of non-utility subsidiaries. The issuance or guaranty of securities by the holding company would not be subject to the prior approval of the state utility commissions. The consolidated enterprise could thus be more highly leveraged than NW Natural and its current subsidiaries. The holding company's ability to pay dividends on its common stock would be subject to the prior rights of holders of the holding company's debt securities (including guarantees) and preferred stock, if any.

In addition, the right of the holding company, as a shareholder, to receive assets of any of its direct or indirect subsidiaries upon the subsidiary's liquidation or reorganization would be subject to the prior rights of the holders of existing and future debt securities and preferred stock issued by such subsidiaries, and, as in the case of dividends, the rights of holders of the holding company common stock to receive any such assets would be subject to the prior rights of the holders of the holding company's debt securities (including guarantees) and preferred stock.

HOLDING COMPANY DIVERSIFICATION RISK. *The holding company may invest in unregulated activities that may prove to be riskier than the current activities of NW Natural, which could result in losses and adversely affect the holding company's financial condition, results of operations and cash flows.*

The holding company structure may allow us greater opportunities to invest in regulated and unregulated businesses. These investments may involve greater risk than an investment in NW Natural. If losses are incurred in unregulated businesses, they will likely not be recoverable through utility rates and they could adversely affect the holding company's financial condition, results of operations and cash flows.

EMPLOYEE BENEFIT RISK. *The cost of providing pension and postretirement healthcare benefits is subject to changes in pension assets and liabilities, changing employee demographics and changing actuarial assumptions, which may have an adverse effect on our financial condition, results of operations and cash flows.*

Until we closed the pension plans to new hires, which for non-union employees was in 2006 and for union employees was in 2009, we provided pension plans and postretirement healthcare benefits to eligible full-time utility employees and retirees. Most of our current utility employees were hired prior to these dates, and therefore remain eligible for these plans. Our cost of providing such benefits is subject to changes in the market value of our pension assets, changes in employee demographics including longer life expectancies, increases in healthcare costs, current and future legislative changes, and various actuarial calculations and assumptions. The actuarial assumptions used to calculate our future pension and postretirement healthcare expense may differ materially from actual results due to significant market fluctuations and changing withdrawal rates, wage rates, interest rates and other factors. These differences may result in an adverse impact on the amount of pension contributions, pension expense or other postretirement benefit costs recorded in future periods. Sustained declines in equity markets and reductions in bond rates may have a material adverse effect on the value of our pension fund assets and liabilities. In these circumstances, we may be required to recognize increased contributions and pension expense earlier than we had planned to the extent that the value of pension assets is less than the total anticipated liability under the plans, which could have a negative impact on our financial condition, results of operations and cash flows.

WORKFORCE RISK. *Our business is heavily dependent on being able to attract and retain qualified employees and maintain a competitive cost structure with market-based salaries and employee benefits, and workforce disruptions could adversely affect our operations and results.*

Our ability to implement our business strategy and serve our customers is dependent upon our continuing ability to attract and retain talented professionals and a technically skilled workforce, and being able to transfer the knowledge and expertise of our workforce to new employees as our largely older workforce retires. We expect that a significant portion of our workforce will retire within the current decade, which will require that we attract, train and retain skilled workers to prevent loss of institutional knowledge or skills gap. Without an appropriately skilled workforce, our ability to provide quality service and meet our regulatory requirements will be challenged and this could negatively impact our earnings. Additionally, within our utility segment, a majority of our workers are represented by the OPEIU Local No.11 AFL-CIO, and are covered by a collective bargaining agreement that extends to November 30, 2019. Disputes with the union representing our employees over terms and conditions of their agreement could result in instability in our labor relationship and work stoppages that could impact the timely delivery of gas and other services from our utility and storage facilities, which could strain relationships with customers and state regulators and cause a loss of revenues. Our collective bargaining agreements may also limit our flexibility in dealing with our workforce, and our ability to change work rules and practices and implement other efficiency-related improvements to successfully compete in today's challenging marketplace, which may negatively affect our financial condition and results of operations.

LEGISLATIVE, COMPLIANCE AND TAXING AUTHORITY RISK. *We are subject to governmental regulation, and compliance with local, state and federal requirements, including taxing requirements, and unforeseen changes in or interpretations of such requirements could affect our financial condition and results of operations.*

We are subject to regulation by federal, state and local governmental authorities. We are required to comply with a variety of laws and regulations and to obtain authorizations, permits, approvals and certificates from governmental agencies in various aspects of our business. Significant changes in federal, state, or local governmental leadership can accelerate or amplify changes in existing laws or regulations, or the manner in which they are interpreted or enforced. For example, the U.S. Presidential Administration has made numerous leadership changes at federal administrative agencies since the 2016 U.S. Presidential election. Moreover, the U.S. Congress and the U.S. Presidential Administration may make substantial changes to fiscal, tax, regulation and other federal policies. The U.S. Presidential Administration has called for significant changes to U.S. fiscal policies, U.S. trade, healthcare, immigration, foreign, and government regulatory policy. To the extent the U.S. Congress or U.S. Presidential Administration implements changes to U.S. policy, those changes may impact, among other things, the U.S. and global economy, international trade and relations, unemployment, immigration, corporate taxes, healthcare, the U.S. regulatory environment, inflation and other areas. Although we cannot predict the impact, if any, of these changes to our business, they could adversely affect our financial condition and results of operations. Until we know what policy changes are made and how those changes impact our business and the business of our competitors over the long term, we will not know if, overall, we will benefit from them or be negatively affected by them.

Though we cannot predict the changes in laws, regulations, or enforcement that are likely as a result of these transitions, we expect there to be a number of significant changes. We cannot predict with certainty the impact of any future revisions or changes in interpretations of existing regulations or the adoption of new laws and regulations. Additionally, any failure to comply with existing or new laws and regulations could result in fines, penalties or injunctive measures that could affect operating assets. For example, under the Energy Policy Act of 2005, the FERC has civil authority under the Natural Gas Act to impose penalties for current violations of up to $1 million per day for each violation. In addition, as the regulatory environment for our industry increases in complexity, the risk of inadvertent noncompliance may also increase. Changes in regulations, the imposition of additional regulations, and the failure to comply with laws and regulations could negatively influence our operating environment and results of operations.

Additionally, changes in federal, state or local tax laws and their related regulations, or differing interpretations or enforcement of applicable law by a federal, state or local taxing authority, could result in substantial cost to us and negatively affect our results of operations. Tax law and its related regulations and case law are inherently complex and dynamic. Disputes over interpretations of tax laws may be settled with the taxing authority in examination, upon appeal or through litigation. Our judgments may include reserves for potential adverse outcomes regarding tax positions that have been taken that may be subject to challenge by taxing authorities. Changes in laws, regulations or adverse judgments and the inherent difficulty in quantifying potential tax effects of business decisions may negatively affect our financial condition and results of operations.

In this regard, the Tax Cuts and Jobs Act of 2017 was approved by the U.S. Congress on December 20, 2017 and signed into law by the U.S. President on December 22, 2017. This legislation makes significant changes to the U.S. Internal Revenue Code. Such changes include a reduction in the corporate tax rate from 35% to 21% and limitations on certain corporate deductions and credits, among other changes. Certain of these changes may negatively affect our financial condition and results of operations.

We expect that the elimination of bonus depreciation may increase taxes in 2018 and 2019, which may have an adverse effect on cash flows during this period. In addition, there is uncertainty as to how our regulators will reflect the impact of the legislation in rates. The resulting ratemaking treatment may negatively affect our financial condition and results of operations.

SAFETY REGULATION RISK. *We may experience increased federal, state and local regulation of the safety of our systems and operations, which could adversely affect our operating costs and financial results.*

The safety and protection of the public, our customers and our employees is and will remain our top priority. We are committed to consistently monitoring and maintaining our distribution system and storage operations to ensure that natural gas is acquired, stored and delivered safely, reliably and efficiently. Given recent high-profile natural gas explosions, leaks and accidents in other parts of the country involving both distribution systems and storage facilities, we anticipate that the natural gas industry may be the subject of even greater federal, state and local regulatory oversight. For example, in 2016, the Protecting our Infrastructure of Pipelines and Enhancing Safety Act (PIPES Act) was signed into law increasing regulations for natural gas storage pipelines and underground storage facilities. Similarly, in 2016, California passed legislation directing the Department of Oil, Gas and Geothermal Resources (DOGGR) to develop regulations affecting gas storage operations. DOGGR has issued proposed regulations which we expect to go into effect within the first half of 2018. As currently written, these regulations require mechanical integrity testing and implementation of gas flow limited to tubing only for all wells at Gill Ranch within the next 7 years.

We intend to work diligently with industry associations and federal and state regulators to seek to ensure compliance with these and other new laws. We expect there to be increased costs associated with compliance, and those costs could be significant. If these costs are not recoverable in our customer rates, they could have a negative impact on our operating costs and financial results.

HEDGING RISK. *Our risk management policies and hedging activities cannot eliminate the risk of commodity price movements and other financial market risks, and our hedging activities may expose us to additional liabilities for which rate recovery may be disallowed, which could result in an adverse impact on our operating revenues, costs, derivative assets and liabilities and operating cash flows.*

Our gas purchasing requirements expose us to risks of commodity price movements, while our use of debt and equity financing exposes us to interest rate, liquidity and other financial market risks. In our Utility segment, we attempt to manage these exposures with both financial and physical hedging mechanisms, including our gas reserves transactions which are hedges backed by physical gas supplies. While we have risk management procedures for hedging in place, they may not always work as planned and cannot entirely eliminate the risks associated with hedging. Additionally, our hedging activities may cause us to incur additional expenses to obtain the hedge. We do not hedge our entire interest rate or commodity cost exposure, and the unhedged exposure will vary over time. Gains or losses experienced through hedging activities, including carrying costs, generally flow through the PGA mechanism or are recovered in future general rate cases. However, the hedge transactions we enter into for the utility are subject to a prudence review by the OPUC and WUTC, and, if found imprudent, those expenses may be, and have been previously, disallowed, which could have an adverse effect on our financial condition and results of operations.

In addition, our actual business requirements and available resources may vary from forecasts, which are used as the basis for our hedging decisions, and could cause our exposure to be more or less than we anticipated. Moreover, if our derivative instruments and hedging transactions do not qualify for regulatory deferral and we do not elect hedge accounting treatment under generally accepted accounting standards, our results of operations and financial condition could be adversely affected.

We also have credit-related exposure to derivative counterparties. Counterparties owing us money or physical natural gas commodities could breach their obligations. Should the counterparties to these arrangements fail to perform, we may be forced to enter into alternative arrangements to meet our normal business requirements. In that event, our financial results could be adversely affected. Additionally, under most of our hedging arrangements, any downgrade of our senior unsecured long-term debt credit rating could allow our counterparties to require us to post cash, a letter of credit or other form of collateral, which would expose us to additional costs and may trigger significant increases in borrowing from our credit facilities if the credit rating downgrade is below investment grade. Further, based on current interpretations, we are not considered a "swap dealer" or "major swap participant" in 2017, so we are exempt from certain requirements under the Dodd-Frank Act. If we are unable to claim this exemption, we could be subject to higher costs for our derivatives activities.

INABILITY TO ACCESS CAPITAL MARKET RISK. *Our inability to access capital, or significant increases in the cost of capital, could adversely affect our financial condition and results of operations.*

Our ability to obtain adequate and cost effective short-term and long-term financing depends on maintaining investment grade credit ratings as well as the existence of liquid and stable financial markets. Our businesses rely on access to capital and bank markets, including commercial paper, bond and equity markets, to finance our operations, construction expenditures and other business requirements, and to refund maturing debt that cannot be funded entirely by internal cash flows. Disruptions in capital markets could adversely affect our ability to access short-term and long-term financing. Our access to funds under committed credit facilities, which are currently provided by a number of banks, is dependent on the ability of the participating banks to meet their funding commitments. Those banks may not be able to meet their funding commitments if they experience shortages of capital and liquidity. Disruptions in the bank or capital financing markets as a result of economic uncertainty, changing or increased regulation of the financial sector, or failure of major financial institutions could adversely affect our access to capital and negatively impact our ability to run our business and make strategic investments.

A negative change in our current credit ratings, particularly below investment grade, could adversely affect our cost of borrowing and access to sources of liquidity and capital. Such a downgrade could further limit our access to borrowing under available credit lines. Additionally, downgrades in our current credit ratings below investment grade could cause additional delays in accessing the capital markets by the utility while we seek supplemental state regulatory approval, which could hamper our ability to access credit markets on a timely basis. A credit downgrade could also require additional support in the form of letters of credit, cash or other forms of collateral and otherwise adversely affect our financial condition and results of operations.

REPUTATIONAL RISKS. *Customers', legislators', and regulators' opinions of us are affected by many factors, including system reliability and safety, protection of customer information, rates, media coverage, and public sentiment. To the extent that customers, legislators, or regulators have or develop a negative opinion of us, our financial positions, results of operations and cash flows could be adversely affected.*

A number of factors can affect customer satisfaction including: service interruptions or safety concerns due to failures of equipment or facilities or from other causes, and our ability to promptly respond to such failures; our ability to safeguard sensitive customer information; and the timing and magnitude of rate increases, and volatility of rates. Customers', legislators', and regulators' opinions of us can also be affected by media coverage, including the proliferation of social media, which may include information, whether factual or not, that damages our brand and reputation.

If customers, legislators, or regulators have or develop a negative opinion of us and our utility services, this could result in increased regulatory oversight and could affect the returns on common equity we are allowed to earn. Additionally, negative opinions about us could make it more difficult for us to achieve favorable legislative or regulatory outcomes. Negative opinions could also result in sales volumes reductions or increased use of other sources of energy. Any of these consequences could adversely affect our financial position, results of operations and cash flows.

Risks Related Primarily to Our Local Utility Business

REGULATORY ACCOUNTING RISK. *In the future, we may no longer meet the criteria for continued application of regulatory accounting practices for all or a portion of our regulated operations.*

If we could no longer apply regulatory accounting, we could be required to write off our regulatory assets and precluded from the future deferral of costs not recovered through rates at the time such amounts are incurred, even if we are expected to recover these amounts from customers in the future.

GAS PRICE RISK. *Higher natural gas commodity prices and volatility in the price of gas may adversely affect our results of operations and cash flows.*

The cost of natural gas is affected by a variety of factors, including weather, changes in demand, the level of production and availability of natural gas supplies, transportation constraints, availability and cost of pipeline capacity, federal and state energy and environmental regulation and legislation, natural disasters and other catastrophic events, national and worldwide economic and political conditions, and the price and availability of alternative fuels. In our utility segment, the cost we pay for natural gas is generally passed through to our customers through an annual PGA rate adjustment. If gas prices were to increase significantly, it would raise the cost of energy to our utility customers, potentially causing those customers to conserve or switch to alternate sources of energy. Significant price increases could also cause new home builders and commercial developers to select alternative energy sources. Decreases in the volume of gas we sell could reduce our earnings, and a decline in customers could slow growth in our future earnings. Additionally, because a portion of any (10% or 20%) difference between the estimated average PGA gas cost in rates and the actual average gas cost incurred is recognized as current income or expense, higher average gas costs than those assumed in setting rates can adversely affect our operating cash flows, liquidity and results of operations. Additionally, notwithstanding our current rate structure, higher gas costs could result in increased pressure on the OPUC or the WUTC to seek other means to reduce rates, which also could adversely affect our results of operations and cash flows.

Higher gas prices may also cause us to experience an increase in short-term debt and temporarily reduce liquidity because we pay suppliers for gas when it is purchased, which can be in advance of when these costs are recovered through rates. Significant increases in the price of gas can also slow our collection efforts as customers experience increased difficulty in paying their higher energy bills, leading to higher than normal delinquent accounts receivable resulting in greater expense associated with collection efforts and increased bad debt expense.

CUSTOMER GROWTH RISK. *Our utility margin, earnings and cash flow may be negatively affected if we are unable to sustain customer growth rates in our local gas distribution segment.*

Our utility margins and earnings growth have largely depended upon the sustained growth of our residential and commercial customer base due, in part, to the new construction housing market, conversions of customers to natural gas from other energy sources and growing commercial use of natural gas. The last recession slowed new construction. While construction has resumed and the multi-family composition has been higher than its pre-recession pace, overall construction has not returned to the pre-recession pace. Insufficient growth in these markets, for economic, political or other reasons could result in an adverse long-term impact on our utility margin, earnings and cash flows.

RISK OF COMPETITION. *Our gas distribution business is subject to increased competition which could negatively affect our results of operations.*

In the residential and commercial markets, our gas distribution business competes primarily with suppliers of electricity, fuel oil, and propane. In the industrial market, we compete with suppliers of all forms of energy. Competition among these forms of energy is based on price, efficiency, reliability, performance, market conditions, technology, environmental impacts and public perception.

Technological improvements in other energy sources such as heat pumps, batteries or other alternative technologies could erode our competitive advantage. If natural gas prices rise relative to other energy sources, or if the cost, environmental impact or public perception of such other energy sources improves relative to natural gas, it may negatively affect our ability to attract new customers or retain our existing residential, commercial and industrial customers, which could have a negative impact on our customer growth rate and results of operations.

RELIANCE ON THIRD PARTIES TO SUPPLY NATURAL GAS RISK. *We rely on third parties to supply the natural gas in our distribution segment, and limitations on our ability to obtain supplies, or failure to receive expected supplies for which we have contracted, could have an adverse impact on our financial results.*

Our ability to secure natural gas for current and future sales depends upon our ability to purchase and receive delivery of supplies of natural gas from third parties. We, and in some cases, our suppliers of natural gas do not have control over the availability of natural gas supplies, competition for those supplies, disruptions in those supplies, priority allocations on transmission pipelines, or pricing of those supplies. Additionally, third parties on whom we rely may fail to deliver gas for which we have contracted. If we are unable or are limited in our ability to obtain natural gas from our current suppliers or new sources, we may not be able to meet our customers' gas requirements and would likely incur costs associated with actions necessary to mitigate services disruptions, both of which could significantly and negatively impact our results of operations.

SINGLE TRANSPORTATION PIPELINE RISK. *We rely on a single pipeline company for the transportation of gas to our service territory, a disruption of which could adversely impact our ability to meet our customers' gas requirements.*

Our distribution system is directly connected to a single interstate pipeline, which is owned and operated by Northwest Pipeline. The pipeline's gas flows are bi-directional, transporting gas into the Portland metropolitan market from two directions: (1) the north, which brings supplies from the British Columbia and Alberta supply basins; and (2) the east, which brings supplies from the Alberta and the U.S. Rocky Mountain supply basins. If there is a rupture or inadequate capacity in the pipeline, we may not be able to meet our customers' gas requirements and we would likely incur costs associated with actions necessary to mitigate service disruptions, both of which could significantly and negatively impact our results of operations.

WEATHER RISK. *Warmer than average weather may have a negative impact on our revenues and results of operations.*

We are exposed to weather risk primarily in our utility segment. A majority of our volume is driven by gas sales to space heating residential and commercial customers during the winter heating season. Current utility rates are based on an assumption of average weather. Warmer than average weather typically results in lower gas sales. Colder weather typically results in higher gas sales. Although the effects of warmer or colder weather on utility margin in Oregon are expected to be mitigated through the operation of our weather normalization mechanism, weather variations from normal could adversely affect utility margin because we may be required to purchase more or less gas at spot rates, which may be higher or lower than the rates assumed in our PGA. Also, a portion of our Oregon residential and commercial customers (usually less than 10%) have opted out of the weather normalization mechanism, and 11% of our customers are located in Washington where we do not have a weather normalization mechanism. These effects could have an adverse effect on our financial condition, results of operations and cash flows.

CUSTOMER CONSERVATION RISK. *Customers' conservation efforts may have a negative impact on our revenues.*

An increasing national focus on energy conservation, including improved building practices and appliance efficiencies may result in increased energy conservation by customers. This can decrease our sales of natural gas and adversely affect our results of operations because revenues are collected mostly through volumetric rates, based on the amount of gas sold. In Oregon, we have a conservation tariff which is designed to recover lost utility margin due to declines in residential and small commercial customers' consumption. However, we do not have a conservation tariff in Washington that provides us this margin protection on sales to customers in that state.

RELIANCE ON TECHNOLOGY RISK. *Our efforts to integrate, consolidate and streamline our operations have resulted in increased reliance on technology, the failure or security breach of which could adversely affect our financial condition and results of operations.*

Over the last several years we have undertaken a variety of initiatives to integrate, standardize, centralize and streamline our operations. These efforts have resulted in greater reliance on technological tools such as: an enterprise resource planning system, an automated dispatch system, an automated meter reading system, a customer information system, a web-based ordering and tracking system, and other similar technological tools and initiatives. The failure of any of these or other similarly important technologies, or our inability to have these technologies supported, updated, expanded or integrated into other technologies, could adversely impact our operations. We take precautions to protect our systems, but there is no guarantee that the procedures we have implemented to protect against unauthorized access to secured data and systems are adequate to safeguard against all security breaches. Our utility could experience breaches of security pertaining to sensitive customer, employee, and vendor information maintained by the utility in the normal course of business, which could adversely affect the utility's reputation, diminish customer confidence, disrupt operations, materially increase the costs we incur to protect against these risks, and subject us to possible financial liability or increased regulation or litigation, any of which could adversely affect our financial condition and results of operations.

Furthermore, we rely on information technology systems in our operations of our distribution and storage operations. There are various risks associated with these systems, including, hardware and software failure, communications failure, data distortion or destruction, unauthorized access to data, misuse of proprietary or confidential data, unauthorized control through electronic means, programming mistakes and other inadvertent errors or deliberate human acts. In particular, cyber security attacks, terrorism or other malicious acts could damage, destroy or disrupt all of our business systems. Any failure of information technology systems could result in a loss of operating revenues, an increase in operating expenses and costs to repair or replace damaged assets. As these potential cyber security attacks become more common and sophisticated, we could be required to incur costs to strengthen our systems or obtain specific insurance coverage against potential losses.

Risks Related Primarily to Our Gas Storage Businesses

LONG-TERM LOW OR STABILIZATION OF GAS PRICE RISK. *Any significant stabilization of natural gas prices or long-term low gas prices could have a negative impact on the demand for our natural gas storage services, which could adversely affect our financial results.*

Storage businesses benefit from price volatility, which impacts the level of demand for services and the rates that can be charged for storage services. Largely due to the abundant supply of natural gas made available by hydraulic fracturing techniques, natural gas prices have dropped significantly to levels that are near historic lows. If prices and volatility remain low or decline further, then the demand for storage services, and the prices that we will be able to charge for those services, may decline or be depressed for a prolonged period of time. Prices below the costs to operate the storage facility could result in a decision to shut-in all or a portion of the facility. A sustained decline in these prices or a shut-in of all or a portion of the facility could have an adverse impact on our financial condition, results of operations and cash flows.

NATURAL GAS STORAGE COMPETITION RISK. *Increasing competition in the natural gas storage business could reduce the demand for our storage services and drive prices down for storage, which could adversely affect our financial condition, results of operations and cash flows.*

Our natural gas storage segment competes primarily with other storage facilities and pipelines. Natural gas storage is an increasingly competitive business, with the ability to expand or build new storage capacity in California, the U.S. Rocky Mountains and elsewhere in the United States and Canada. Increased competition in the natural gas storage business could reduce the demand for our natural gas storage services, drive prices down for our storage business, and adversely affect our ability to renew or replace existing contracts at rates sufficient to maintain current revenues and cash flows, which could adversely affect our financial condition, results of operations and cash flows.

IMPAIRMENT OF LONG-LIVED ASSETS RISK. *Additional impairments of the value of long-lived assets could have a material effect on our financial condition, or results of operations.*

We review the carrying value of long-lived assets whenever events or changes in circumstances indicate the carrying amount of the assets might not be recoverable. The determination of recoverability is based on the undiscounted net cash flows expected to result from the operation of such assets. Projected cash flows depend on the future operating costs and projected revenues associated with the asset, storage pricing, the ability to contract with higher value customers, and the future market and price for gas storage over the remaining life of the asset. We recognized a $192.5 million impairment of long-lived assets at the Gill Ranch Facility as of December 31, 2017. Further changes in revenues, operating costs, or a decision to sell the facility may result in an additional impairment of long-lived assets at the Gill Ranch Facility. Additionally, we review our other long-lived assets to determine if an impairment analysis is necessary. Any impairment charge taken with respect to our long-lived assets could be material and could have a material effect on our financial condition and results of operations.

THIRD-PARTY PIPELINE RISK. *Our gas storage businesses depend on third-party pipelines that connect our storage facilities to interstate pipelines, the failure or unavailability of which could adversely affect our financial condition, results of operations and cash flows.*

Our gas storage facilities are reliant on the continued operation of a third-party pipeline and other facilities that provide delivery options to and from our storage facilities. Because we do not own all of these pipelines, their operations are not within our control. If the third-party pipeline to which we are connected were to become unavailable for current or future withdrawals or injections of natural gas due to repairs, damage to the infrastructure, lack of capacity or other reasons, our ability to operate efficiently and satisfy our customers' needs could be compromised, thereby potentially having an adverse impact on our financial condition, results of operations and cash flows.

ITEM 1B. UNRESOLVED STAFF COMMENTS

We have no unresolved comments.

ITEM 2. PROPERTIES

Utility Properties

Our natural gas pipeline system consists of approximately 20,000 miles of distribution and transmission mains located in our service territory in Oregon and Washington. In addition, the pipeline system includes service pipelines, meters and regulators, and gas regulating and metering stations. Pipeline mains are located in municipal streets or alleys pursuant to franchise or occupation ordinances, in county roads or state highways pursuant to agreements or permits granted pursuant to statute, or on lands of others pursuant to easements obtained from the owners of such lands. We also hold permits for the crossing of numerous navigable waterways and smaller tributaries throughout our entire service territory.

We own service building facilities in Portland, Oregon, as well as various satellite service centers, garages, warehouses, and other buildings necessary and useful in the conduct of our business. We also lease office space in Portland for our corporate headquarters, which expires on May 31, 2020. Resource centers are maintained on owned or leased premises at convenient points in the distribution system to provide service within our utility service territory. We also own LNG storage facilities in Portland and near Newport, Oregon.

In October 2017, we entered into a 20-year operating lease agreement for a new headquarters in Portland in anticipation of the expiration of our current lease in 2020. We executed an extensive search and evaluation process that focused on seismic preparedness, safety, reliability, the least cost to our customers, and a continued commitment to our employees and the communities we serve. Payments under the new lease are expected to commence in 2020.

Gas Storage Properties

We hold leases and other property interests in approximately 12,000 net acres of underground natural gas storage in Oregon, approximately 5,000 net acres of underground natural gas storage in California, and easements and other property interests related to pipelines associated with those facilities. We own rights to depleted gas reservoirs near Mist, Oregon that are continuing to be developed and operated as underground gas storage facilities. We also hold all future storage rights in certain other areas of the Mist gas field in Oregon, as well as in California related to the Gill Ranch Facility.

We consider all of our properties currently used in our operations, both owned and leased, to be well maintained, in good operating condition, and, along with planned additions, adequate for our present and foreseeable future needs.

Our Mortgage and Deed of Trust (Mortgage) is a first mortgage lien on substantially all of the property constituting our utility plant.

ITEM 3. LEGAL PROCEEDINGS

Other than the proceedings disclosed in Note 15, we have only nonmaterial litigation in the ordinary course of business.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our common stock is listed and trades on the New York Stock Exchange under the symbol NWN. The high and low trades for our common stock during the past two years were as follows:

	2017		2016	
Quarter Ended	High	Low	High	Low
March 31	$ 61.70	$ 56.53	$ 54.51	$ 48.90
June 30	63.40	57.65	64.84	49.46
September 30	68.60	59.15	66.17	57.96
December 31	69.50	58.55	61.85	53.50

The closing price for our common stock on the last trading day of 2017 and 2016 was $59.65 and $59.80, respectively.

As of February 16, 2018, there were 5,213 holders of record of our common stock.

Dividends per share paid during the past two years were as follows:

Payment Month	2017	2016
February	$ 0.4700	$ 0.4675
May	0.4700	0.4675
August	0.4700	0.4675
November	0.4725	0.4700
Total per share	$ 1.8825	$ 1.8725

The declaration and amount of future dividends depend upon our earnings, cash flows, financial condition, and other factors. The amount and timing of dividends payable on our common stock are within the sole discretion of our Board of Directors. Subject to Board approval, we expect to continue paying cash dividends on our common stock on a quarterly basis.

The following table provides information about purchases of our equity securities that are registered pursuant to Section 12 of the Securities Exchange Act of 1934 during the quarter ended December 31, 2017:

Issuer Purchases of Equity Securities

Period	Total Number of Shares Purchased(1)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs(2)	Maximum Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs(2)
Balance forward			2,124,528	$ 16,732,648
10/01/17-10/31/17	657	$ 66.33	—	—
11/01/17-11/30/17	14,239	67.89	—	—
12/01/17-12/31/17	650	64.98	—	—
Total	15,546	67.71	2,124,528	$ 16,732,648

(1) During the quarter ended December 31, 2017, the following number of shares of our common stock were purchased on the open market: 13,539 shares to meet the requirements of our Dividend Reinvestment and Direct Stock Purchase Plan and 2,007 shares to meet the requirements of our share-based programs. No shares of our common stock were accepted as payment for stock option exercises pursuant to our Restated Stock Option Plan.

(2) During the quarter ended December 31, 2017, no shares of our common stock were repurchased pursuant to our Board-Approved share repurchase program. For more information on this program, see Note 6.

ITEM 6. SELECTED FINANCIAL DATA

	For the year ended December 31,				
In thousands, except per share data	2017	2016	2015	2014	2013
Operating revenues	$ 762,173	$ 675,967	$ 723,791	$ 754,037	$ 758,518
Net income (loss)	(55,623)	58,895	53,703	58,692	60,538
Earnings (Loss) per share of common stock:					
Basic	$ (1.94)	$ 2.13	$ 1.96	$ 2.16	$ 2.24
Diluted	(1.94)	2.12	1.96	2.16	2.24
Dividends paid per share of common stock	1.88	1.87	1.86	1.85	1.83
Total assets, end of period	$ 3,039,746	$ 3,079,801	$ 3,069,410	$ 3,056,326	$ 2,960,808
Total equity	742,776	850,497	780,972	767,321	751,872
Long-term debt	683,184	679,334	569,445	613,095	671,643

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following is management's assessment of Northwest Natural Gas Company's (NW Natural or the Company) financial condition, including the principal factors that affect results of operations. The discussion refers to our consolidated results for the years ended December 31, 2017, 2016, and 2015. References in this discussion to "Notes" are to the Notes to Consolidated Financial Statements in Item 8 of this report.

The consolidated financial statements include NW Natural and its direct and indirect wholly-owned subsidiaries including:

- NW Natural Energy, LLC (NWN Energy);
- NW Natural Gas Storage, LLC (NWN Gas Storage);
- Gill Ranch Storage, LLC (Gill Ranch);
- NNG Financial Corporation (NNG Financial);
- Northwest Energy Corporation (Energy Corp);
- NW Natural Water Company, LLC (NWN Water); and
- NWN Gas Reserves LLC (NWN Gas Reserves).

We operate in two primary reportable business segments: local gas distribution and gas storage. We also have other investments and business activities not specifically related to one of these two reporting segments, which we aggregate and report as other. We refer to our local gas distribution business as the utility, and our gas storage segment and other as non-utility. Our utility segment includes our NW Natural local gas distribution business, NWN Gas Reserves, which is a wholly-owned subsidiary of Energy Corp, and the utility portion of our Mist underground storage facility in Oregon (Mist). Our gas storage segment includes NWN Gas Storage, which is a wholly-owned subsidiary of NWN Energy, Gill Ranch, which is a wholly-owned subsidiary of NWN Gas Storage, the non-utility portion of Mist, and asset management services. Other includes NWN Energy's equity investment in Trail West Holding, LLC (TWH), which is pursuing the development of a proposed natural gas pipeline through its wholly-owned subsidiary, Trail West Pipeline, LLC (TWP), NNG Financial's investment in Kelso-Beaver Pipeline (KB Pipeline), and NWN Water, which pursuing investments in the water sector itself and through its wholly-owned subsidiary FWC Merger Sub, Inc. For a further discussion of our business segments and other, see Note 4.

NON-GAAP FINANCIAL MEASURES. In addition to presenting the results of operations and earnings amounts in total, certain financial measures are expressed in cents per share or exclude the effects of certain items, which are non-GAAP financial measures. We present net income or loss and earnings or loss per share adjusted for certain items along with the U.S. GAAP measures to illustrate their magnitude on ongoing business and operational results. Although the excluded amounts are properly included in the determination of net income or loss and earnings or loss per share under U.S. GAAP, we believe the amount and nature these items make period to period comparisons of operations difficult or potentially confusing. We use such non-GAAP financial measures to analyze our financial performance because we believe they provide useful information to our investors and creditors in evaluating our financial condition and results of operations. Our non-GAAP financial measures should not be considered a substitute for, or superior to, measures calculated in accordance with U.S. GAAP. Reconciliations of the non-GAAP financial measures to their closest U.S. GAAP measure used in subsequent sections of Item 7 are provided below.

NON-GAAP RECONCILIATIONS	2017		2016		2015	
In millions, except per share data	Amount	Per Share	Amount	Per Share	Amount	Per Share
Consolidated net income (loss)	$ (55.6)	$ (1.94)	$ 58.9	$ 2.12	$ 53.7	$ 1.96
Adjustments:						
Regulatory environmental disallowance[1]	—	—	3.3	0.12	15.0	0.55
Impairment of long-lived assets[2]	192.5	6.71	—	—	—	—
Tax effects on TCJA[3]	(21.4)	(0.75)	—	—	—	—
Tax effects on non-GAAP adjustments	(51.0)	(1.78)	(1.3)	(0.05)	(5.9)	(0.22)
Adjusted consolidated net income	$ 64.5	$ 2.24	$ 60.9	$ 2.19	$ 62.8	$ 2.29
Utility net income (loss)	$ 60.5	$ 2.11	$ 54.6	$ 1.96	$ 53.4	$ 1.95
Adjustments:						
Regulatory environmental disallowance[1]	—	—	3.3	0.12	15.0	0.55
Tax effects on TCJA[3]	1.0	0.03	—	—	—	—
Tax effects on non-GAAP adjustments	—	—	(1.3)	(0.05)	(5.9)	(0.22)
Adjusted utility net income	$ 61.5	$ 2.14	$ 56.6	$ 2.03	$ 62.5	$ 2.28
Gas storage net income (loss)	$ (116.2)	$ (4.05)	$ 4.3	$ 0.16	$ 0.2	$ 0.01
Adjustments:						
Impairment of long-lived assets[2]	192.5	6.71	—	—	—	—
Tax effects on TCJA[3]	(21.9)	(0.76)	—	—	—	—
Tax effects on non-GAAP adjustments	(51.0)	(1.78)	—	—	—	—
Adjusted gas storage net income	$ 3.4	$ 0.12	$ 4.3	$ 0.16	$ 0.2	$ 0.01
Other net income (loss)	$ 0.1	$ —	$ —	$ —	$ 0.1	$ —
Adjustments:						
Tax effects on TCJA[3]	(0.6)	(0.02)	—	—	—	—
Adjusted other net income (loss)	$ (0.5)	$ (0.02)	$ —	$ —	$ 0.1	$ —

(1) Regulatory environmental disallowance of $3.3 million in 2016 includes $2.8 million recorded in utility other income (expense), net and $0.5 million recorded in utility operations and maintenance expense. Regulatory environmental disallowance of $15.0 million in 2015 is recorded in utility operations and maintenance expense. The tax effect of both years' adjustments are calculated using a combined federal and state statutory rate of 39.5%. EPS amounts for the 2016 and 2015 adjustments are calculated using diluted shares of 27.8 million and 27.4 million, respectively, as shown on our Consolidated Statements of Comprehensive Income (Loss).

(2) Non-cash impairment of long-lived assets at the Gill Ranch Facility of $192.5 million was recorded on December 31, 2017. The tax effect of this adjustment is calculated using our new combined federal and state statutory tax rate of 26.5%. EPS amounts are calculated using diluted shares of 28.7 million as shown on our Consolidated Statements of Comprehensive Income (Loss). See Part II, Item 7, "Application of Critical Accounting Policies and Estimates—Impairment of Long-Lived Assets" for additional information on the impairment analysis.

(3) Non-cash Tax Cuts and Jobs Act (TCJA) benefit (expense) of $21.4 million was recorded in income tax expense (benefit) in the fourth quarter of 2017 as a result of the federal tax rate changing from 35% to 21% effective December 22, 2017. EPS amounts are calculated using diluted shares of 28.7 million as shown on our Consolidated Statements of Comprehensive Income (Loss), and the TCJA impacts in the segments and other may not correlate exactly to the consolidated amount due to rounding. See Note 9 for additional information on TCJA.

EXECUTIVE SUMMARY

We manage our business and strategic initiatives with a long-term view of providing natural gas service safely and reliably to customers, working with regulators on key policy initiatives, and remaining focused on growing our business. See *"2018 Outlook"* below for more information. Highlights for the year include:

- added over 12,700 customers in 2017 for a growth rate of 1.8% at December 31, 2017;
- invested $214 million in our distribution system and facilities for growth and reliability;
- completed key components of the North Mist Gas Storage Expansion Project with $107 million capital expenditures incurred as of December 31, 2017, with an additional $20 to $30 million expected in 2018;
- ranked first in the West in the 2017 J.D. Powers' Gas Utility Residential Customer Satisfaction Study and Gas Utility Business Customer Satisfaction Study;
- filed for a general rate increase in Oregon for first time in six years;
- delivered increasing dividends for the 62nd consecutive year; and
- announced our intent to expand into the regulated water utility sector by entering into agreements to acquire two small privately owned water utilities.

Key financial highlights include:

	2017		2016		2015	
In millions, except per share data	Amount	Per Share	Amount	Per Share	Amount	Per Share
Consolidated net income (loss)	$ (55.6)	$ (1.94)	$ 58.9	$ 2.12	$ 53.7	$ 1.96
Adjusted consolidated net income(1)	$ 64.5	$ 2.24	$ 60.9	$ 2.19	$ 62.8	$ 2.29
Utility margin	$ 392.6		$ 376.6		$ 371.4	
Gas storage operating revenues	$ 23.6		$ 25.3		$ 21.4	

(1) See the Non-GAAP Reconciliations table at the beginning of Item 7 for a reconciliation of this non-GAAP measure to its closest U.S.GAAP measure.

2017 COMPARED TO 2016. Consolidated net loss was $55.6 million compared to consolidated net income of $58.9 million in 2016, including $192.5 million pre-tax for the impairment of long-lived assets at the Gill Ranch Facility and the $21.4 million benefit associated with TCJA in 2017, and the $3.3 million pre-tax regulatory environmental disallowance in 2016.

Excluding these items, adjusted consolidated net income increased $3.6 million. See the Non-GAAP reconciliations at the beginning of Item 7 for additional information. Adjusted consolidated net income increased $3.6 million primarily due to the following factors:

- a $16.0 million increase in utility margin primarily due to customer growth and effects of colder than average weather in 2017 compared to warmer than average weather in 2016; and
- a $3.1 million increase in other income (expense), net primarily due an increase of the equity portion of AFUDC; partially offset by
- a $15.7 million increase in operations and maintenance expense driven by higher utility payroll and benefits increases, as well as increased safety equipment upgrade costs; and
- a $1.6 million decrease in gas storage revenues driven by lower revenues from our asset management agreements for our Mist storage and transportation capacity.

2016 COMPARED TO 2015. Overall, consolidated net income increased $5.2 million. The increase was primarily due to the $9.1 million after-tax charge from 2015 and a $2.0 million after-tax charge in 2016 related to the regulatory disallowances associated with a February 2015 OPUC Order and subsequent Order in our SRRM docket.

Excluding the impact of the non-cash charges from the SRRM docket in 2015 and 2016, adjusted consolidated net income decreased $1.9 million primarily due to the following factors:

- a $7.0 million increase in operations and maintenance expense primarily due to cost savings initiatives that were implemented in the second half of 2015 that did not recur in 2016; and
- a $5.5 million decrease in other income (expense), net primarily related to the recognition of $5.3 million of equity earnings on deferred regulatory asset balances as a result of the 2015 OPUC Order; partially offset by
- a $5.2 million increase in utility margin primarily due to customer growth and gains from gas cost incentive sharing; and
- a $3.9 million increase in gas storage revenues largely due to higher revenues from our asset management agreements at both storage facilities and slightly higher contract values at the Gill Ranch Facility for the 2016-17 gas year.

2018 OUTLOOK

Our 2018 goals leverage our resources and history of innovation to continue meeting the evolving needs of customers, regulators, and shareholders. Our near-term outlook is centered on following six long-term strategic objectives:

Deliver Gas	Grow Our Businesses
Ensure Safe and Reliable Service	Enable Utility Growth
Provide a Superior Customer Experience	Lead in a Low-Carbon Future
Advance Constructive Policies and Regulation	Pursue Strategic Investments

SAFETY AND RELIABILITY. Delivering natural gas safely and reliably to customers is our first priority. During 2018, we will maintain our vigilant focus on safety and emergency response through our hands-on scenario-based training for our employees, third-party contractors, and local authorities. To ensure reliability, resiliency, and safety of our infrastructure, we intend to continue to invest in the maintenance and necessary upgrades of our pipeline system, including multi-year projects to replace end-of-life equipment at our Mist storage facility and renovate several resource centers. Safety also includes our vigilance in maintaining strong cybersecurity defenses and preparing for large-scale emergency events, such as seismic hazards in our region.

SUPERIOR CUSTOMER EXPERIENCE. NW Natural has a legacy of providing excellent customer service and a long-standing dedication to continuous improvement, which have resulted in consistently high rankings in the J.D. Power and Associates customer satisfaction studies. In 2018, we will continue to enhance our customers' experience to meet their evolving expectations by prioritizing improvements to technology which supports our customers' frequent interactions and highest value touchpoints.

POLICIES AND REGULATION. We remain committed to working constructively with policymakers and regulators to provide the best outcomes for both our customers and shareholders. We are working closely with the Oregon commission and other stakeholders on several significant dockets, including the best way to return TCJA benefits to our customers and process our Oregon general rate case, which we filed in December 2017. The rate case supports the continued investment and maintenance of our system for safety, reliability and resiliency. Additionally, we plan to file an updated IRP in 2018 to support the long-term investments needed for the growth and continued reliability of our utility infrastructure. Finally, we will continue working with the EPA and other stakeholders on an environmentally protective and cost effective clean-up for the Portland Harbor Superfund Site.

UTILITY GROWTH. Natural gas is the preferred energy choice in our service territory given its efficient, affordable, and clean-burning qualities. We are focused on leveraging these key attributes to capitalize on our region's strong economic growth. We continue to grow our market share in the single-family residential sector and capture new commercial customers. We have also focused on expanding our share of mixed-use developments, a growing segment of the multifamily housing market, through equipment incentives, streamlined gas infrastructure designs, promotional support, and a recently approved new tariff. We will continue to pursue growth in all sectors in 2018.

LOW-CARBON PATHWAY. The Pacific Northwest and NW Natural are deeply committed to a clean energy future. It's why we launched our low-carbon initiative to further emission savings for both the Company and our communities by leveraging our modern pipeline systems in new ways, working closely with customers, policymakers and regulators, and embracing cutting-edge technology. We have partnered with the City of Portland to bring renewable natural gas (RNG) onto our system. We expect the entire project to be operational in 2019. We will continue helping our customers reduce and offset their consumption as we support the development of renewable natural gas supply and explore other cutting edge solutions to lower the carbon intensity of our product, such as power to gas.

STRATEGIC INVESTMENTS. We remain focused on creating value in all our businesses. We are investing in the regulated utility expansion of our Mist gas storage facility, which will provide innovative no-notice gas storage service for a local electric company who will use the reliability of natural gas to integrate more intermittent renewable energy — like solar and wind — into the energy grid. In 2017, we announced our intent to expand into the regulated water utility sector and will continue pursuing this strategy in 2018 with a focus on water sector investments that fit our conservative risk profile and core competencies. Our pursuit of a holding company structure is important to this growth strategy. With the OPUC and WUTC approvals for a holding company reorganization received, we will be focused on seeking shareholder approval for conversion to a holding company structure at our 2018 annual shareholders' meeting and executing on the conversions in late 2018 or early 2019.

HOLDING COMPANY

Formation of a Holding Company

Holding company structures are well-established corporate structures, and exist across all industries. In the utility industry, holding companies have become the norm, and are employed for the same purposes holding companies are used in other industries. NW Natural intends to pursue formation of a holding company to best position it to be able to respond to opportunities and risks in a manner that serves the best interests of its shareholders and customers. We have received regulatory approval from the OPUC and WUTC and expect regulatory approval from the CPUC to reorganize into a holding company structure. Our Board of Directors has determined to recommend a holding company structure to our shareholders for vote at our 2018 Annual Shareholders Meeting. If our shareholders approve, the Board and Management must take additional actions to implement the holding company structure, which we currently expect to happen in the latter half of 2018 or at the beginning of 2019. To implement a holding company structure, NW Natural common stock would be converted or exchanged into the same relative percentages of the holding company that they own of NW Natural immediately prior to the reorganization. The structure currently contemplated involves placing a non-operating corporate entity over the existing consolidated structure, and “ring-fencing” NW Natural as described below to insulate the gas utility from the operations of the holding company and its other direct and indirect subsidiaries. NW Natural management continuously looks for growth opportunities that would build on core competencies and match the risk profile that NW Natural and its shareholders seek. We believe a holding company structure is a more agile and efficient platform from which to pursue, finance and oversee new business growth opportunities, such as in the water sector. Following the formation of the holding company, NW Natural would continue to operate as a gas utility subject to the jurisdiction of the OPUC and the WUTC.

Holding Company Regulatory Restrictions and Conditions

The regulatory approvals for the formation of a holding company require NW Natural and its holding company to enter into and file an agreement with the OPUC and the WUTC, which includes a number of “ring-fencing” conditions. The ring-fencing provisions are designed to operate the gas utility business conservatively and insulate it from risks associated with other holding company businesses. The ring-fencing and other provisions of the approvals include the following:

- NW Natural may not pay dividends or make distributions to the holding company if NW Natural’s credit ratings and common equity levels fall below specified ratings and levels. If NW Natural’s long-term secured credit ratings are below A- for S&P and A3 for Moody’s, dividends may be issued so long as NW Natural’s common equity is 45% or above. If NW Natural’s long-term secured credit ratings are below BBB for S&P and Baa2 for Moody’s, dividends may be issued so long as NW Natural’s common equity is 46% or above. Dividends may not be issued if NW Natural’s long-term secured credit ratings fall to BB+ or below for S&P or Ba1 or below for Moody’s, or if NW Natural’s common equity is below 44%. In each case, with the common equity level to be determined on a preceding or projected 13-month basis.
- Maintenance of separate credit ratings, long-term debt ratings, and preferred stock ratings, if any, by NW Natural and its holding company;
- In the event NW Natural’s common equity, on a preceding or projected basis, falls below 46%, NW Natural is required to notify the OPUC, and if the level of common equity falls below 44%, file a plan with the OPUC to restore its equity to that level. Under the WUTC order, the average equity component must not exceed 56%;
- NW Natural must have one director who is independent from NW Natural management and from the holding company;
- NW Natural and its subsidiaries will not be permitted to hold holding company investments, except under NW Natural-sponsored employee benefit plans or employee compensation plans;
- NW Natural must issue one share of preferred stock to an independent party and require that NW Natural may only file a voluntary petition for bankruptcy if approved unanimously by the Board of Directors of NW Natural, including the independent director, and by the holder of the preferred share;
- As is the case currently, NW Natural will be prohibited from cross-subsidizing any business, including the holding company and its unregulated subsidiaries;
- The costs of the holding company reorganization must be separately tracked and not charged or allocated to NW Natural, and those costs and all other costs related to future business endeavors of the holding company must be excluded from NW Natural rate cases. NW Natural and its holding company are required to guarantee that NW Natural customers will not be harmed by any increases in NW Natural costs that result from the holding company reorganization, including any higher costs of debt or equity, higher revenue requirement, tax costs, or rate of return, due to the reorganization; and
- For three years, NW Natural will be required to provide an annual $500,000 credit to Oregon customers and a $55,000 credit to Washington customers. Cost-savings over $50,000 that are allocable to NW Natural as a result of holding company acquisition activity will be deferred and credited to Oregon and Washington customers until after NW Natural’s next general rate case following the Company’s 2017 general rate case.

DIVIDENDS

Dividend highlights include:

Per common share	2017	2016	2015
Dividends paid	$ 1.8825	$ 1.8725	$ 1.8625

In January 2018, the Board of Directors declared a quarterly dividend on our common stock of $0.4725 per share, payable on February 15, 2018, to shareholders of record on January 31, 2018, reflecting an indicated annual dividend rate of $1.89 per share.

RESULTS OF OPERATIONS

Regulatory Matters

Regulation and Rates

UTILITY. Our utility business is subject to regulation by the OPUC, WUTC, and FERC with respect to, among other matters, rates and terms of service. The OPUC and WUTC also regulate the system of accounts and issuance of securities by our utility. In 2017, approximately 89% of our utility gas customers were located in Oregon, with the remaining 11% in Washington. Earnings and cash flows from utility operations are largely determined by rates set in general rate cases and other proceedings in Oregon and Washington. They are also affected by the local economies in Oregon and Washington, the pace of customer growth in the residential, commercial, and industrial markets, and our ability to remain price competitive, control expenses, and obtain reasonable and timely regulatory recovery of our utility-related costs, including operating expenses and investment costs in utility plant and other regulatory assets. See "*Most Recent General Rate Cases"* below.

GAS STORAGE. Our gas storage business is subject to regulation by the OPUC, WUTC, CPUC, and FERC with respect to, among other matters, rates and terms of service. The OPUC and CPUC also regulate the issuance of securities, system of accounts, and regulate intrastate storage services. The FERC regulates interstate storage services. The FERC uses a maximum cost of service model which allows for gas storage prices to be set at or below the cost of service as approved by each agency in their last regulatory filing. The OPUC Schedule 80 rates are tied to the FERC rates, and are updated whenever we modify our FERC maximum rates. The CPUC regulates Gill Ranch under a market-based rate model which allows for the price of storage services to be set by the marketplace. In 2017, approximately 70% of our storage revenues were derived from FERC, Oregon, and Washington regulated operations and approximately 30% from California operations.

Most Recent General Rate Cases

OREGON. Effective November 1, 2012, the OPUC authorized rates to customers based on an ROE of 9.5%, an overall rate of return of 7.78%, and a capital structure of 50% common equity and 50% long-term debt.

WASHINGTON. Effective January 1, 2009, the WUTC authorized rates to customers based on an ROE of 10.1% and an overall rate of return of 8.4% with a capital structure of 51% common equity, 5% short-term debt, and 44% long-term debt.

FERC. We are required under our Mist interstate storage certificate authority and rate approval orders to file every five years either a petition for rate approval or a cost and revenue study to change or justify maintaining the existing rates for our interstate storage services. In December 2013, we filed a rate petition, which was approved in 2014, and allows for the maximum cost-based rates for our interstate gas storage services. These rates were effective January 1, 2014, with the rate changes having no significant impact on our revenues. In January 2018, various state parties filed a request with the FERC to adjust the revenue requirements of public utilities to reflect the recent reduction in the federal corporate income tax rate and other impacts resulting from the TCJA. We will monitor this request and work the FERC to evaluate the potential impact to these approved rates.

We continuously monitor the utility and evaluate the need for a rate case. In December 2017, we filed a rate case in Oregon with the OPUC. For additional information, see "Regulatory Proceeding Updates—*Rate Case"* below.

Regulatory Proceeding Updates

During 2017, we were involved in the regulatory activities discussed below.

HEDGING. In 2014, the OPUC opened a docket to discuss broader gas hedging practices across gas utilities in Oregon. In January 2018, the OPUC accepted the parties' proposal to follow a uniform process to address any future proposed long-term hedges and closed the docket.

The WUTC also conducted an investigation into the hedging practices of gas utilities operating in Washington and considered whether it should require gas utilities to implement certain hedging practices. The WUTC issued and outlined their policy in March 2017. The policy supports risk-responsive hedging strategies that are adaptable to variability in the market and required gas utilities to submit with their 2017 PGA a preliminary hedging plan that outlines the utilities' intended path to incorporate risk-responsive hedging strategies. Beginning with the 2018 PGA, gas utilities must submit an annual comprehensive hedging plan that supports integration of risk responsive strategies into their hedging framework. Beginning with the 2019 PGA filing, utilities must provide a full strategy implementation plan for year 2020 and beyond. As directed by the WUTC, we submitted our preliminary hedging plan with our 2017 PGA in September 2017, and plan to submit our annual comprehensive hedging plan with our 2018 PGA.

INTERSTATE STORAGE AND OPTIMIZATION SHARING. We received an Order from the OPUC in March 2015 on their review of the current revenue sharing arrangement that allocates a portion of the net revenues generated from non-utility Mist storage services and third-party asset management services to utility customers. The Order requires a third-party cost study to be performed and the results of the cost study may initiate a new docket or the re-opening of the original docket. In 2017, a third-party consultant completed a cost study. We will continue to work with all stakeholders as we review this completed study, and expect resolution of this docket in 2018.

INTEGRATED RESOURCE PLAN (IRP). We file a full IRP with Oregon and Washington bi-annually and file updates between filings. Our last full IRPs were filed in 2016, and we received a letter of compliance from the WUTC in December of 2016 and acknowledgment by the OPUC in February of 2017. The IRP included analysis of different growth scenarios and corresponding resource acquisition strategies. The analysis is needed to develop supply and demand resource requirements, consider uncertainties in the planning process, and establish a plan for providing reliable and low cost natural gas service. We anticipate filing our next full IRP in 2018.

DEPRECIATION STUDY. Under OPUC regulations, the utility is required to file a depreciation study every five years to update or justify maintaining the existing depreciation rates. In December 2016, we filed the required depreciation study with the Commission. In September 2017, the parties to the docket filed a settlement with the Commission requesting approval of updated depreciation rates negotiated with the parties. In January 2018, OPUC issued an order adopting the stipulation. The depreciation rates included in the stipulation do not materially change our current depreciation rates.

HOLDING COMPANY APPLICATION. In February 2017, we filed applications with the OPUC, WUTC, and CPUC for approval to reorganize under a holding company structure. In 2017, the OPUC and WUTC approved our applications subject to certain restrictions or "ring-fencing" provisions applicable to NW Natural, the entity that currently, and would continue to, house our utility operations, and the holding company. We continue to work with the CPUC, and expect resolutions by the end of the first quarter of 2018.

MULTI-FAMILY TARIFF. In June 2017, we filed a request with the OPUC to create a multi-family tariff to establish an optional program to serve the mixed-use, multi-family residential market. Under the tariff, NW Natural will provide upfront incentives for builders to offset the initial cost of installing natural gas piping to individual units, and then recover the costs of the incentives through a fixed charge on the customer's monthly bills. In July 2017, the OPUC approved the tariff allowing us to further serve the multi-family customer sector.

TAX REFORM DEFERRAL. In December 2017, we filed applications with the OPUC and WUTC to defer the overall net benefit associated with the TCJA that was enacted on December 22, 2017 with a January 1, 2018 effective date. We anticipate the impacts from the TCJA will accrue to our customers in a manner approved by the Commissions. We will continue to work with the OPUC and WUTC on this throughout 2018. See Note 9 for more information on TCJA.

REGULATED WATER UTILITY. In December 2017, we entered into agreements to acquire two privately-owned water utilities: Salmon Valley Water Company, based in Welches, Oregon, and Falls Water Company, based in Idaho Falls, Idaho. These transactions are subject to certain conditions, including approvals from the OPUC and the Idaho Public Utilities Commission (IPUC), respectively. In January 2018, we filed our application with the OPUC to acquire Salmon Valley Water Company and filed with the IPUC in February 2018 to acquire Falls Water Company. We do not expect these transactions or their continuing operations to have a material financial impact. We continue to work with the OPUC and IPUC and anticipate receiving approvals and completing these acquisitions in 2018.

GENERAL RATE CASE. On December 29, 2017, we filed an Oregon general rate case requesting a 6% revenue increase, after an adjustment for the conservation tariff deferral, to continue operating and maintaining our distribution system and continue providing safe, reliable service to our customers. Our December general rate case filing was based on the following:

- forward test year from November 1, 2018 through October 31, 2019;
- capital structure of 50% debt and 50% equity;
- return on equity of 10.0%;
- cost of capital of 7.62%; and
- rate base of $1.19 billion, an increase of $304 million since the last Oregon rate case in 2012.

The general rate case filing in December 2017 does not include the benefit to customers' rates of the newly passed federal tax legislation. In the coming months, we will be working with the OPUC to determine how to return these benefits to customers, and we expect to amend or refile our rate case to incorporate the benefit of the TCJA, which would likely lower the original revenue requirement requested. It is possible through this rate case proceeding or another proceeding that the OPUC will also determine how to treat historical deferred tax liabilities, which may result in additional changes to our rate case request as well. The general rate case review and approval process could take up to 10 months with new rates anticipated to be effective November 1, 2018.

Rate Mechanisms

During 2017, our approved rates and recovery mechanisms for each service area included:

	Oregon	Washington
Authorized Rate Structure:		
ROE	9.5%	10.1%
ROR	7.8%	8.4%
Debt/Equity Ratio	50%/50%	49%/51%
Key Regulatory Mechanisms:		
PGA	X	X
Gas Cost Incentive Sharing	X	
Decoupling	X	
WARM	X	
Environmental Cost Deferral	X	X
SRRM	X	
Pension Balancing	X	
Interstate Storage Sharing	X	X

PURCHASED GAS ADJUSTMENT. Rate changes are established for the utility each year under PGA mechanisms in Oregon and Washington to reflect changes in the expected cost of natural gas commodity purchases. This includes gas costs under spot purchases as well as contract supplies, gas costs hedged with financial derivatives, gas costs from the withdrawal of storage inventories, the production of gas reserves, interstate pipeline demand costs, temporary rate adjustments, which amortize balances of deferred regulatory accounts, and the removal of temporary rate adjustments effective for the previous year.

In September 2017, we filed our PGA and received OPUC and WUTC approval in October 2017. PGA rate changes were effective November 1, 2017. The rate changes decreased the average monthly bills of residential customers by approximately 6.4% and 3.1% in Oregon and Washington, respectively. The decrease in Oregon reflected customers' portion of adjustments mainly for the effect of changes in wholesale natural gas costs and for a portion of WARM amounts that exceeded the maximum monthly allowable amount to be returned to customers during the 2016-17 gas year. Oregon rates were offset by adjustments related to our energy efficiency programs and additional annual adjustments based on ongoing orders with the OPUC. Washington rates reflected the effect of changes in wholesale natural gas costs.

Each year, we typically hedge gas prices on a portion of our utility's annual sales requirement based on normal weather, including both physical and financial hedges. We entered the 2017-18 gas year with our forecasted sales volumes hedged at 49% in financial swap and option contracts and 26% in physical gas supplies. For additional hedging matters from the WUTC and OPUC, see "Regulatory Proceeding Updates—*Hedging*" above.

As of December 31, 2017, we have also hedged future gas years with approximately 24% for the 2018-19 gas year and between 4% and 11% over the subsequent five gas years for utility's annual sales requirements based on normal weather. Our hedge levels are subject to change based on actual load volumes, which depend, to a certain extent, on weather, economic conditions, and estimated gas reserve production. Also, our gas storage inventory levels may increase or decrease with storage expansion, changes in storage contracts with third parties, variations in the heat content of the gas, and/or storage recall by the utility.

Under the current PGA mechanism in Oregon, there is an incentive sharing provision whereby we are required to select each year an 80% deferral or a 90% deferral of higher or lower actual gas costs compared to estimated PGA prices, such that the impact on current earnings from the incentive sharing is either 20% or 10% of the difference between actual and estimated gas costs, respectively. For the 2016-17 and 2017-18 gas years, we selected the 90% deferral option. Under the Washington PGA mechanism, we defer 100% of the higher or lower actual gas costs, and those gas cost differences are passed on to customers through the annual PGA rate adjustment.

EARNINGS TEST REVIEW. We are subject to an annual earnings review in Oregon to determine if the utility is earning above its authorized ROE threshold. If utility earnings exceed a specific ROE level, then 33% of the amount above that level is required to be deferred or refunded to customers. Under this provision, if we select the 80% deferral gas cost option, then we retain all of our earnings up to 150 basis points above the currently authorized ROE. If we select the 90% deferral option, then we retain all of our earnings up to 100 basis points above the currently authorized ROE. For the 2015-16 gas year, we selected the 80% deferral option. For the 2016-17 and 2017-18 gas years, we selected the 90% deferral option. The ROE threshold is subject to adjustment annually based on movements in long-term interest rates. For calendar years 2015, 2016, and 2017, the ROE threshold was 10.60%, 11.06%, and 10.66%, respectively. There were no refunds required for 2015 and 2016. We do not expect a refund for 2017 based on our results and anticipate filing the 2017 earnings test in May 2018.

GAS RESERVES. In 2011, the OPUC approved the Encana gas reserves transaction to provide long-term gas price protection for our utility customers and determined our costs under the agreement would be recovered on an ongoing basis through our annual PGA mechanism. Gas produced from our interests is sold at then prevailing market prices, and revenues from such sales, net of associated operating and production costs and amortization, are included in our cost of gas. The cost of gas, including a carrying cost for the rate base investment made under the original agreement, is included in our annual Oregon PGA filing, which allows us to recover these costs through customer rates. Our net investment under the original agreement earns a rate of return.

In 2014, we amended the original gas reserves agreement in response to Encana's sale of its interest in the Jonah field located in Wyoming to Jonah Energy. Under our amended agreement with Jonah Energy, we have the option to invest in additional wells on a well-by-well basis with drilling costs and resulting gas volumes shared at our amended proportionate working interest for each well in which we invest. Volumes produced from the additional wells drilled after our amended agreement are included in our Oregon PGA at a fixed rate of $0.4725. We did not have the opportunity to participate in additional wells in 2015, 2016, or 2017.

DECOUPLING. In Oregon, we have a decoupling mechanism. Decoupling is intended to break the link between utility earnings and the quantity of gas consumed by customers, removing any financial incentive by the utility to discourage customers' efforts to conserve energy. The Oregon decoupling mechanism was reauthorized and the baseline expected usage per customer was set in the 2012 Oregon general rate case. This mechanism employs a use-per-customer decoupling calculation, which adjusts margin revenues to account for the difference between actual and expected customer volumes. The margin adjustment resulting from differences between actual and expected volumes under the decoupling component is recorded to a deferral account, which is included in the annual PGA filing. In Washington, customer use is not covered by such a tariff.

WARM. In Oregon, we have an approved weather normalization mechanism, which is applied to residential and commercial customer bills. This mechanism is designed to help stabilize the collection of fixed costs by adjusting residential and commercial customer billings based on temperature variances from average weather, with rate decreases when the weather is colder than average and rate increases when the weather is warmer than average. The mechanism is applied to bills from December through May of each heating season. The mechanism adjusts the margin component of customers' rates to reflect average weather, which uses the 25-year average temperature for each day of the billing period. Daily average temperatures and 25-year average temperatures are based on a set point temperature of 59 degrees Fahrenheit for residential customers and 58 degrees Fahrenheit for commercial customers. The collections of any unbilled WARM amounts due to tariff caps and floors are deferred and earn a carrying charge until collected in the PGA the following year. This weather normalization mechanism was reauthorized in the

2012 Oregon general rate case without an expiration date. Residential and commercial customers in Oregon are allowed to opt out of the weather normalization mechanism, and as of December 31, 2017, 9% of total customers had opted out. We do not have a weather normalization mechanism approved for residential and commercial Washington customers, which account for about 11% of total customers. See "Business Segments—Local Gas Distribution Utility Operations" below.

INDUSTRIAL TARIFFS. The OPUC and WUTC have approved tariffs covering utility service to our major industrial customers, which are intended to give us certainty in the level of gas supplies we need to acquire to serve this customer group. The approved terms include, among other things, an annual election period, special pricing provisions for out-of-cycle changes, and a requirement that industrial customers complete the term of their service election under our annual PGA tariff.

ENVIRONMENTAL COST DEFERRAL AND SRRM. We have a SRRM through which we track and have the ability to recover past deferred and future prudently incurred environmental remediation costs allocable to Oregon, subject to an earnings test.

Under the SRRM collection process, there are three types of deferred environmental remediation expense:

- Pre-review - This class of costs represents remediation spend that has not yet been deemed prudent by the OPUC. Carrying costs on these remediation expenses are recorded at our authorized cost of capital. We anticipate the prudence review for annual costs and approval of the earnings test prescribed by the OPUC to occur by the third quarter of the following year.
- Post-review - This class of costs represents remediation spend that has been deemed prudent and allowed after applying the earnings test, but is not yet included in amortization. We earn a carrying cost on these amounts at a rate equal to the five-year treasury rate plus 100 basis points.
- Amortization - This class of costs represents amounts included in current customer rates for collection and is generally calculated as one-fifth of the post-review deferred balance. We earn a carrying cost equal to the amortization rate determined annually by the OPUC, which approximates a short-term borrowing rate. We included $7.4 million and $10.0 million of deferred remediation expense approved by the OPUC for collection during the 2017-18 and 2016-17 PGA years, respectively.

In addition, the SRRM also provides for the annual collection of $5.0 million from Oregon customers through a tariff rider. As we collect amounts from customers, we recognize these collections as revenue and separately amortize an equal and offsetting amount of our deferred regulatory asset balance through the environmental remediation operating expense line shown separately in the operating expense section of our Consolidated Statement of Comprehensive Income (Loss). See Note 15 for more information on our environmental matters.

The SRRM earnings test is an annual review of our adjusted utility ROE compared to our authorized utility ROE, which is currently 9.5%. To apply the earnings test first we must determine what if any costs are subject to the test through the following calculation:

Annual spend
Less: $5.0 million base rate rider(1)
Prior year carry-over(2)
$5.0 million insurance + interest on insurance
Total deferred annual spend subject to earnings test
Less: over-earnings adjustment, if any
Add: deferred interest on annual spend(3)
Total amount transferred to post-review

(1) Base rate rider went into Oregon customer rates beginning November 1, 2015.
(2) Prior year carry-over results when the prior year amount transferred to post-review is negative. The negative amount is carried over to offset annual spend in the following year.
(3) Deferred interest is added to annual spend to the extent the spend is recoverable.

To the extent the utility earns at or below its authorized ROE, the total amount transferred to post-review is recoverable through the SRRM. To the extent the utility earns more than its authorized ROE in a year, the amount transferred to post-review would be reduced by those earnings that exceed its authorized ROE.

For 2017, we have performed this test, which we anticipate submitting to the OPUC in May 2018, and we do not expect an earnings test adjustment for 2017.

The WUTC has also previously authorized the deferral of environmental costs, if any, that are appropriately allocated to Washington customers. This Order was effective in January 2011 with cost recovery and carrying charges on amount deferred for costs associated with services provided to Washington customers to be determined in a future proceeding. Annually, or more often if circumstances warrant, we review all regulatory assets for recoverability. If we should determine all or a portion of these regulatory assets no longer meet the criteria for continued application of regulatory accounting, then we would be required to write-off the net unrecoverable balances against earnings in the period such a determination was made.

PENSION COST DEFERRAL AND PENSION BALANCING ACCOUNT. The OPUC permits us to defer annual pension expenses above the amount set in rates, with recovery of these deferred amounts through the implementation of a balancing account, which includes the expectation of higher and lower pension expenses in future years. Our recovery of these deferred balances includes accrued interest on the account balance at the utility's authorized rate of return. Future years' deferrals will depend on changes in plan assets and projected benefit liabilities based on a number of key assumptions and our pension contributions. Pension expense deferrals, excluding interest, were $6.5 million, $6.3 million, and $8.2 million in 2017, 2016 and 2015, respectively.

INTERSTATE STORAGE AND OPTIMIZATION SHARING. On an annual basis, we credit amounts to Oregon and Washington customers as part of our regulatory incentive sharing mechanism related to net revenues earned from Mist gas storage and asset management activities. Generally, amounts are credited to Oregon customers in June, while credits are given to customers in Washington through reductions in rates through the annual PGA filing in November.

The following table presents the credits to customers:

In millions	2017	2016	2015
Oregon utility customer credit	$ 11.7	$ 9.4	$ 9.6
Washington utility customer credit	1.0	1.0	0.8

Business Segments - Local Gas Distribution Utility Operations

Utility margin results are primarily affected by customer growth, revenues from rate-base additions, and, to a certain extent, by changes in delivered volumes due to weather and customers' gas usage patterns because a significant portion of our utility margin is derived from natural gas sales to residential and commercial customers. In Oregon, we have a conservation tariff (also called the decoupling mechanism), which adjusts utility margin up or down each month through a deferred regulatory accounting adjustment designed to offset changes resulting from increases or decreases in average use by residential and commercial customers. We also have a weather normalization tariff in Oregon, WARM, which adjusts customer bills up or down to offset changes in utility margin resulting from above- or below-average temperatures during the winter heating season. Both mechanisms are designed to reduce, but not eliminate, the volatility of customer bills and our utility's earnings. See "Regulatory Matters—*Rate Mechanisms*" above.

Utility segment highlights include:

Dollars and therms in millions, except EPS data	2017	2016	2015
Utility net income	$ 60.5	$ 54.6	$ 53.4
Adjusted utility net income(1)	61.5	56.6	62.5
EPS - utility segment	2.11	1.96	1.95
Adjusted EPS - utility segment(1)	2.14	2.03	2.28
Gas sold and delivered (in therms)	1,240	1,085	1,029
Utility margin(2)	$ 392.6	$ 376.6	$ 371.4

(1) See the Non-GAAP Reconciliations table at the beginning of Item 7 for a reconciliation of this non-GAAP measure to its closest U.S.GAAP measure.

(2) See Utility Margin Table below for a reconciliation and additional detail.

2017 COMPARED TO 2016. Utility net income was $60.5 million in 2017 compared to $54.6 million in 2016, which includes the $1.0 million loss associated with the TCJA in 2017 and the after-tax $2.0 million regulatory environmental disallowance in 2016. See the Non-GAAP reconciliations at the beginning of Item 7 for additional information. Excluding these items, adjusted utility net income increased $5.0 million, or $0.11 per share. The primary factors contributing to this increase in adjusted utility net income were as follows:

- a $16.0 million increase in utility margin primarily due to:
  - a $6.8 million increase from customer growth; partially offset by
  - a $2.7 million decrease in gains in gas cost incentive sharing due to actual gas prices being lower than those estimated in the 2016-17 PGA, but not by the same magnitude as in the prior period.
  - a portion of the remaining increase was due to the effects of colder than average weather in 2017 compared to warmer than average weather in 2016.
- a $3.1 million increase in other income (expense), net, primarily due to an increase in the equity portion of AFUDC in 2017; partially offset by
- a $9.5 million increase in operations and maintenance expense driven largely from payroll and benefits due to increased headcount, general salary increases, and increased safety equipment update costs; and
- a $3.4 million increase in depreciation expense primarily due to additional capital expenditures.

Total utility volumes sold and delivered in 2017 increased 14% over 2016 primarily due to the impact of weather that was 28% colder than the prior period and 7% colder than average.

2016 COMPARED TO 2015. The primary factors contributing to the $1.2 million, or $0.01 per share, increase in utility net income were as follows:

- a $5.2 million increase in utility margin primarily due to:
  - a $5.7 million increase from customer growth;
  - a $0.8 million increase from gains in gas cost incentive sharing resulting from lower gas prices than those estimated in the PGA; partially offset by
  - a $1.3 million decrease due to lower contributions from our gas reserve investments, which decreased due to amortization.
- an $8.3 million decrease in operations and maintenance expense primarily due to the environmental disallowance recognized in 2015, offset in part by increases in payroll costs due to additional headcount and general pay increases along with increased non-payroll costs for professional services and contract work; partially offset by
- an $8.7 million, decrease in other income (expense), net, primarily due to the environmental interest disallowance recognized in 2016 and the recognition of $5.3 million of equity earnings on deferred regulatory asset balances in 2015; and
- a $1.9 million, increase in depreciation expense primarily due to additional capital expenditures.

Total utility volumes sold and delivered in 2016 increased 5% over 2015 primarily due to comparatively colder weather in the first quarter during our peak heating season and colder weather in December 2016.

UTILITY MARGIN TABLE. The following table summarizes the composition of utility gas volumes, revenues, and cost of sales:

In thousands, except degree day and customer data	2017	2016	2015	Favorable/(Unfavorable) 2017 vs. 2016	Favorable/(Unfavorable) 2016 vs. 2015
Utility volumes (therms):					
Residential and commercial sales	740,369	609,222	570,728	131,147	38,494
Industrial sales and transportation	499,924	475,774	457,884	24,150	17,890
Total utility volumes sold and delivered	1,240,293	1,084,996	1,028,612	155,297	56,384
Utility operating revenues:					
Residential and commercial sales	$ 684,214	$ 604,390	$ 644,835	$ 79,824	$ (40,445)
Industrial sales and transportation	63,925	59,386	71,495	4,539	(12,109)
Other revenues	3,872	3,812	3,914	60	(102)
Less: Revenue taxes	19,069	17,111	18,034	1,958	(923)
Total utility operating revenues	732,942	650,477	702,210	82,465	(51,733)
Less: Cost of gas	325,019	260,588	327,305	(64,431)	66,717
Less: Environmental remediation expense	15,291	13,298	3,513	(1,993)	(9,785)
Utility margin	$ 392,632	$ 376,591	$ 371,392	$ 16,041	$ 5,199
Utility margin:[1]					
Residential and commercial sales	$ 355,736	$ 338,060	$ 334,134	$ 17,676	$ 3,926
Industrial sales and transportation	31,847	30,989	30,081	858	908
Miscellaneous revenues	3,865	3,796	3,913	69	(117)
Gain from gas cost incentive sharing	1,237	3,960	3,182	(2,723)	778
Other margin adjustments	(53)	(214)	82	161	(296)
Utility margin	$ 392,632	$ 376,591	$ 371,392	$ 16,041	$ 5,199
Degree days					
Average[2]	4,240	4,256	4,240	(16)	16
Actual	4,553	3,551	3,458	28%	3%
Percent colder (warmer) than average weather[2]	7%	(17)%	(18)%		
Customers - end of period:					
Residential customers	668,803	656,855	646,841	11,948	10,014
Commercial customers	68,050	67,278	66,584	772	694
Industrial customers	1,021	1,013	1,003	8	10
Total number of customers	737,874	725,146	714,428	12,728	10,718
Customer growth:					
Residential customers	1.8%	1.5 %			
Commercial customers	1.1%	1.0 %			
Industrial customers	0.8%	1.0 %			
Total customer growth	1.8%	1.5 %			

(1) Amounts reported as margin for each category of customers are operating revenues, which are net of revenue taxes, less cost of gas and environmental remediation expense.
(2) Average weather represents the 25-year average of heating degree days, as determined in our 2012 Oregon general rate case.

Residential and Commercial Sales

The primary factors that impact results of operations in the residential and commercial markets are customer growth, seasonal weather patterns, energy prices, competition from other energy sources, and economic conditions in our service areas. The impact of weather on margin is significantly reduced through our weather normalization mechanism in Oregon; approximately 80% of our total customers are covered under this mechanism. The remaining customers either opt out of the mechanism or are located in Washington, which does not have a similar mechanism in place. For more information on our weather mechanism, see "Regulatory Matters—Rate Mechanisms—*Weather Normalization Mechanism*" above.

Residential and commercial sales highlights include:

In millions	2017	2016	2015
Volumes (therms):			
Residential sales	465.2	379.2	350.9
Commercial sales	275.2	230.0	219.8
Total volumes	740.4	609.2	570.7
Operating revenues:			
Residential sales	$ 455.9	$ 404.3	$ 424.6
Commercial sales	228.3	200.1	220.2
Total operating revenues	$ 684.2	$ 604.4	$ 644.8
Utility margin:			
Residential:			
Sales	$ 262.1	$ 223.2	$ 211.6
Weather normalization	(11.9)	12.7	14.0
Decoupling	(2.4)	0.8	7.2
Total residential utility margin	247.8	236.7	232.8
Commercial:			
Sales	101.5	87.2	84.8
Weather normalization	(4.6)	5.0	5.8
Decoupling	11.1	9.2	10.7
Total commercial utility margin	108.0	101.4	101.3
Total utility margin	$ 355.8	$ 338.1	$ 334.1

2017 COMPARED TO 2016. The primary factors contributing to changes in the residential and commercial markets were increases of $79.8 million in operating revenue and $17.7 million in utility margin as a result of sales volume increases of 131.2 million therms, or 22%, due to customer growth and the effects of colder than average weather in 2017 compared to warmer than average weather in the prior period.

2016 COMPARED TO 2015. The primary factors contributing to changes in the residential and commercial markets were as follows:

- sales volumes increased 38.5 million therms, or 7%, due to customer growth and comparatively colder weather in the first quarter and December of 2016 compared to record warm weather in 2015;
- operating revenues decreased $40.4 million, due to a 24% decrease in average cost of gas over last year, partially offset by a 7% increase in sales volumes; and
- utility margin increased $4.0 million, due to both residential and commercial customer growth offset by lower contributions from our gas reserve investments, which decreased due to amortization.

Industrial Sales and Transportation

Industrial customers have the option of purchasing sales or transportation services from the utility. Under the sales service, the customer buys the gas commodity from the utility. Under the transportation service, the customer buys the gas commodity directly from a third-party gas marketer or supplier. Our gas commodity cost is primarily a pass-through cost to customers; therefore, our profit margins are not materially affected by an industrial customer's decision to purchase gas from us or from third parties. Industrial and large commercial customers may also select between firm and interruptible service options, with firm services generally providing higher profit margins compared to interruptible services. To help manage gas supplies, our industrial tariffs are designed to provide some certainty regarding industrial customers' volumes by requiring an annual service election which becomes effective November 1, special charges for changes between elections, and in some cases, a minimum or maximum volume requirement before changing options.

Industrial sales and transportation highlights include:

In millions	2017	2016	2015
Volumes (therms):			
Industrial - firm sales	35.7	33.8	32.4
Industrial - firm transportation	167.7	156.9	144.0
Industrial - interruptible sales	55.1	50.4	57.3
Industrial - interruptible transportation	241.4	234.7	224.2
Total volumes	499.9	475.8	457.9
Utility margin:			
Industrial - sales and transportation	$ 31.8	$ 31.0	$ 30.1

2017 COMPARED TO 2016. Sales and transportation volumes increased by 24.1 million therms and utility margin increased $0.8 million due to higher usage from colder than average weather in 2017 compared to warmer than average weather in 2016, and increased usage from higher production load.

2016 COMPARED TO 2015. Sales and transportation volumes increased by 17.9 million therms and utility margin increased $0.9 million due to annual customer service election changes, higher fee revenue due to system restrictions from cold weather in December 2016, and an increase in usage from a few large customers.

Other Revenues

Other revenues include miscellaneous fee income as well as regulatory revenue adjustments, which reflect current period deferrals to and prior year amortizations from regulatory asset and liability accounts, except for gas cost deferrals which flow through cost of gas. Decoupling and other regulatory amortizations from prior year deferrals are included in revenues from residential, commercial, and industrial firm customers.

Other revenue for 2017, 2016, and 2015 remained flat year-over-year as expected.

In millions	2017	2016	2015
Other revenues	$ 3.9	$ 3.8	$ 3.9

Cost of Gas

Cost of gas as reported by the utility includes gas purchases, gas withdrawn from storage inventory, gains and losses from commodity hedges, pipeline demand costs, seasonal demand cost balancing adjustments, regulatory gas cost deferrals, gas reserves costs, and company gas use. The OPUC and WUTC generally require natural gas commodity costs to be billed to customers at the actual cost incurred, or expected to be incurred, by the utility. Customer rates are set each year so that if cost estimates were met we would not earn a profit or incur a loss on gas commodity purchases; however, in Oregon we have an incentive sharing mechanism which has been described under "Regulatory Matters—Rate Mechanisms—*Purchased Gas Adjustment"* above. In addition to the PGA incentive sharing mechanism, gains and losses from hedge contracts entered into after annual PGA rates are effective for Oregon customers are also required to be shared and therefore may impact net income. Further, we also have a regulatory agreement whereby we earn a rate of return on our investment in the gas reserves acquired under the original agreement with Encana and include gas from our amended gas reserves agreement at a fixed rate of $0.4725 per therm, which are also reflected in utility margin. See "Application of Critical Accounting Policies and Estimates—*Accounting for Derivative Instruments and Hedging Activities"* below.

Cost of gas highlights include:

Dollars and therms in millions	2017	2016	2015
Cost of gas	$ 325.0	$ 260.6	$ 327.3
Volumes sold (therms)	831	693	660
Average cost of gas (cents per therm)	$ 0.39	$ 0.38	$ 0.50
Gain from gas cost incentive sharing	1.2	4.0	3.2

2017 COMPARED TO 2016. Cost of gas increased $64.4 million, or 25%, primarily due to the 20% increase in volumes sold due to colder than average weather in 2017 compared to warmer than average weather in 2016, and customer growth.

2016 COMPARED TO 2015. Cost of gas decreased $66.7 million, or 20%, reflecting lower natural gas prices and resulting in a $19.4 million credit to customers, partially offset by a 5% increase in volume mainly from comparatively colder weather in the first quarter and December 2016.

The effect on net income from our gas cost incentive sharing mechanism resulted in a margin gain of $1.2 million, $4.0 million and $3.2 million for 2017, 2016 and 2015, respectively, as actual prices were lower than the estimated prices included in customer rates due to national warmer than average weather, which resulted in lower national natural gas commodity prices. For a discussion of our gas cost incentive sharing mechanism, see "Regulatory Matters—Rate Mechanisms—*Purchased Gas Adjustment*" above.

Business Segments - Gas Storage

Our gas storage segment primarily consists of the non-utility portion of our Mist underground storage facility in Oregon and our 75% undivided ownership interest in the Gill Ranch Facility, an underground storage facility in California. We also contract with an independent energy marketing company to provide asset management services using our utility and non-utility storage and transportation capacity, the results of which are included in the gas storage business segment. For additional information, see also Note 4.

At Mist, we provide gas storage services to customers in the interstate and intrastate markets using storage capacity that has been developed in advance of core utility customers' requirements. Pre-tax income from gas storage at Mist and asset management services is subject to revenue sharing with core utility customers. Under this regulatory incentive sharing mechanism, we retain 80% of pre-tax income from Mist gas storage services and asset management services when the underlying costs of the capacity being used are not included in our utility rates, and 33% of pre-tax income from such storage and asset management services when the capacity being used is included in utility rates. The remaining 20% and 67%, respectively, are credited to a deferred regulatory account for credit to our core utility customers. See "Regulatory Matters—*Regulatory Proceeding Updates*" above for information regarding an open docket related to this incentive sharing mechanism.

Our 75% undivided ownership interest in the Gill Ranch Facility is held by our wholly-owned subsidiary Gill Ranch, LLC, which is also the operator of the facility. Our portion of the facility is approximately 15 Bcf of designed gas storage capacity.

Gas storage segment highlights include:

In millions, except EPS data	2017	2016	2015
Operating revenues	$ 23.6	$ 25.3	$ 21.4
Operating expenses	208.7	16.1	16.3
Gas storage net income (loss)	(116.2)	4.3	0.2
Adjusted gas storage net income(1)	3.4	4.3	0.2
EPS - gas storage segment	(4.05)	0.16	0.01
Adjusted EPS - gas storage segment(1)	0.12	0.16	0.01

(1) See the Non-GAAP Reconciliations table at the beginning of Item 7 for a reconciliation of this non-GAAP measure to its closest U.S.GAAP measure.

2017 COMPARED TO 2016. Our gas storage segment net loss was $116.2 million, or $4.05 per share, compared to net income of $4.3 million, or $0.16 per share, which includes the non-cash after-tax impairment of long-lived assets at the Gill Ranch Facility of $141.5 million in the fourth quarter of 2017 and a $21.9 million benefit associated with the TCJA in 2017. In the fourth quarter, we completed a comprehensive strategic review and evaluation process of the Gill Ranch Facility that evaluated various alternatives, including a potential sale of the asset and we substantially completed contracting for the 2018-19 gas year at lower than anticipated pricing. These events triggered a requirement that management re-evaluate the carrying value of the Gill Ranch Facility. That analysis resulted in the non-cash impairment.

Excluding these items, adjusted gas storage net income decreased $0.9 million, or $0.04 per share, primarily due to a decrease in gas storage revenues largely due to lower asset management revenues from our Mist facility and transportation capacity. See the Non-GAAP reconciliations at the beginning of Item 7 for additional information.

2016 COMPARED TO 2015. Our gas storage segment net income increased $4.1 million, or $0.15 per share, primarily due to the following factors:

- a $3.9 million increase in operating revenue primarily from higher asset management revenues from our Mist facility and transportation capacity, and slightly higher firm contract prices at the Gill Ranch Facility for the 2016-17 gas year; and
- a $2.8 million decrease in interest expense from the early retirement of $20 million of Gill Ranch debt in December 2015.

We have completed contracting for the 2017-18 gas year for our Mist facility, which remains under long-term contracts at similar prices to prior periods. Our Mist facility benefits from limited competition from other Pacific Northwest storage facilities primarily because of its geographic location.

The gas storage market dynamics at the Gill Ranch Facility differ from our Mist facility. Over the past few years, market prices for natural gas storage, particularly in California, were negatively affected by the abundant supply of natural gas, low volatility of natural gas prices, and surplus gas storage capacity.

In 2007, NW Natural's subsidiary Gill Ranch Storage, LLC jointly with Pacific Gas and Electric (PG&E) made an investment decision to build the Gill Ranch Facility, a gas storage facility in California. At that time, our market analysis projected that natural gas storage would be critical in achieving California's renewable portfolio standards and supporting the region's drive to a lower carbon energy landscape. Construction was completed and operations began at the Gill Ranch Facility in 2010 under multi-year storage agreements with terms that ended as the full market implications from the shale gas revolution were transforming the natural gas industry. The additional shale gas eliminated the resource constraints that were expected to exist over the long term and resulted in lower gas prices, decreased seasonal price spreads and volatility, and consequently, reduced the value of gas storage to customers. As a result, over the last few years, we have contracted the Gill Ranch Facility under short-term agreements to allow us to take advantage of any rebound in storage prices or other strategies that would increase revenues.

We have believed and continue to believe that we may see storage price improvement or an increase in the demand for natural gas storage in California in the future driven by a number of factors, including changes in the electric generation triggered by California’s renewable portfolio standards, an increase in use of alternative fuels to meet carbon emissions reduction targets, recovery of the California economy, growth of domestic industrial manufacturing, potential exports of liquefied natural gas from the west coast and other favorable storage market conditions in and around California. We have not seen the rebound in storage prices that we originally anticipated. For the last few years, we have worked diligently to operate the facility efficiently and have been pursuing various strategic alternatives to increase revenues. These efforts included working to identify higher-value customers in and/or near the northern California market that Gill Ranch serves as well as exploring the possibility of providing energy storage services such as compressed gas energy storage (CGES). In the fourth quarter of 2017, we completed our comprehensive strategic review process, which included a sale process for the Gill Ranch Facility, and made a determination that the Gill Ranch Facility is no longer core to our long-term plans.

Additionally, in late 2015, a significant natural gas leak occurred at an unaffiliated southern California gas storage facility. In response to the incident, both state and federal additional regulations were developed. The California Department of Oil, Gas and Geothermal Resources (DOGGR) developed and proposed new regulations for gas storage wells that focus on implementing additional well integrity requirements. DOGGR released a new formulation of these rules on February 12, 2018. Although these rules are subject to a comment period and possible revision, these rules establish a timeframe for completion of compliance of seven years, a period much shorter than the 15 or more years we previously anticipated. In addition, PHMSA proposed new federal regulations for underground natural gas storage facilities that focus on implementing additional pipeline safety requirements of downhole facilities, including operations, maintenance and emergency response activities regarding wells, wellbore tubing, and casing.

While both sets of regulations are still under development, and their ultimate impact is unknown, it is likely that the final PHMSA and DOGGR regulations will likely result in higher costs for all storage providers.

We will continue to evaluate all strategic options for the facility to maximize the value of this asset, and in the meantime, we are committed to operating the facility to the highest safety standards.

Other

Other primarily consists of our non-utility appliance retail center operations, NNG Financial's investment in KB Pipeline, an equity investment in TWH, which has invested in the Trail West pipeline project, and other miscellaneous non-utility investments and business activities. See Note 4 and Note 12 for further details on other activities and our investment in TWH.

Consolidated Operations

Operations and Maintenance

Operations and maintenance highlights include:

In millions	2017	2016	2015
Operations and maintenance	$ 165.2	$ 150.0	$ 157.5

2017 COMPARED TO 2016. Operations and maintenance expense increased $15.3 million, primarily due to the following factors:

- a $6.4 million increase in utility payroll and benefits due to increased headcount and general salary increases; and
- a $1.0 million increase in safety equipment upgrade costs.

2016 COMPARED TO 2015. Operations and maintenance expense decreased $7.5 million, primarily due to the following factors:

- the $15.0 million pre-tax charge for the regulatory disallowance associated with the February 2015 OPUC Order on the recovery of past environmental cost deferrals recorded in 2015. We also expensed an additional $1.0 million related to the 2015 Order; partially offset by
- a $6.5 million increase in non-payroll costs, which returned to a more sustainable level in 2016 after temporary cost savings initiatives in the prior year. Non-payroll increases were primarily related to higher professional service and contract work costs due to general customer service cost increases from system integrity work, and other maintenance; and
- a $1.2 million increase in payroll and benefits due to increased headcount and general pay increases.

Delinquent customer receivable balances continue to remain at historically low levels. The utility's bad debt expense as a percent of revenues was 0.1% for 2017, 2016, and 2015.

In addition to fluctuations in operations and maintenance expense reported above, we have OPUC approval to defer certain utility pension costs in excess of what is currently recovered in customer rates. This pension cost deferral is recorded to a regulatory balancing account, which stabilizes the amount of operations and maintenance expense each year. Pension cost deferrals, excluding interest, were $6.5 million, $6.3 million, and $8.2 million for the years ended December 31, 2017, 2016 and 2015, respectively. As a result, increased pension costs had a minimal effect on operations and maintenance expense in 2017, 2016, and 2015, with the increase principally related to the costs allocated to our Washington operations, which are not covered by the pension balancing account. For further explanation of the pension balancing account, see Note 8 and "Regulatory Matters—Rate Mechanisms—*Pension Cost Deferral and Prepaid Pension Assets*," above.

Depreciation and Amortization

Depreciation and amortization highlights include:

In millions	2017	2016	2015
Depreciation and amortization	$ 85.6	$ 82.3	$ 80.9

2017 COMPARED TO 2016. Depreciation and amortization expense increased by $3.3 million due to utility plant additions that included investments in our natural gas transmission and distribution system, facility upgrades, and enhanced technology.

2016 COMPARED TO 2015. Depreciation and amortization expense increased by $1.4 million due to utility plant additions that included investments in our natural gas transmission and distribution system, storage facilities, and technology.

Other Income (Expense), Net

Other income (expense), net highlights include:

In millions	2017	2016	2015
Equity portion of AFUDC	$ 2.7	$ —	$ —
Gains from company-owned life insurance	2.5	1.7	2.2
Interest income	0.2	0.1	0.1
Loss from equity investments	(0.1)	(0.1)	(0.1)
Net interest income (expense) on deferred regulatory accounts	2.0	(0.1)	8.2
Other non-operating	(2.0)	(2.1)	(2.7)
Total other income (expense), net	$ 5.3	$ (0.5)	$ 7.7

2017 COMPARED TO 2016. Other income (expense), net, increased $5.9 million primarily due to the January 2016 Order from the OPUC, which resulted in a pre-tax $2.8 million interest disallowance in 2016, an increase of $2.7 million in the equity portion of AFUDC, and $0.8 million of gains from company-owned life insurance.

2016 COMPARED TO 2015. Other income (expense), net, increased $8.3 million primarily due to the recognition of $5.3 million of the equity component in interest income from our deferred environmental expenses in the prior year, which did not recur in 2016. We recognized the equity earnings of these deferred regulatory asset balances as a result of the OPUC SRRM Order we received in February 2015. In addition, a January 2016 Order from the OPUC resulted in a write-off of $2.8 million of interest during 2016.

Interest Expense, Net

Interest expense, net highlights include:

In millions	2017	2016	2015
Interest expense, net	$ 38.5	$ 39.1	$ 42.5

2017 COMPARED TO 2016. Interest expense, net decreased $0.6 million primarily due to a $2.1 million increase in the interest-related portion of AFUDC, partially offset by increased interest expense of $1.5 million due to the issuance of long-term debt in December 2016 and August 2017.

2016 COMPARED TO 2015. Interest expense, net of amounts capitalized, decreased $3.4 million primarily due to the redemption of $40 million of utility First Mortgage Bonds (FMBs) in June 2015 and the early retirement of $20 million of Gill Ranch's debt in December 2015, which included a make whole interest provision.

Income Tax Expense
Income tax expense highlights include:

In millions	2017	2016	2015
Income tax (benefit) expense	$ (30.8)	$ 40.7	$ 35.8
Effects of non-GAAP adjustments[1]	51.0	1.3	5.9
Effects from the TCJA[1]	21.4	—	—
Adjusted income tax expense	$ 41.6	$ 42.0	$ 41.7
Effective tax rate	35.6%	40.9%	40.0%
Adjusted effective tax rate	39.2%	40.8%	39.9%

[1] See the Non-GAAP Reconciliations table at the beginning of Item 7 for a reconciliation of this non-GAAP measure to its closest U.S.GAAP measure.

2017 COMPARED TO 2016. Our effective tax rate decreased by 5.3%. Excluding the tax benefits associated with the impairment of long-lived assets at the Gill Ranch Facility and the TCJA enactment in 2017 of $51.0 million and $21.4 million, respectively, and the $1.3 million tax effects of non-GAAP adjustments in 2016, our adjusted effective tax rate decreased 1.6%. See the Non-GAAP reconciliations at the beginning of Item 7 for additional information. The adjusted effective tax rate decreased primarily as a result of AFUDC equity income and increased stock-based compensation deductions in 2017.

2016 COMPARED TO 2015. The increase in the effective income tax rate is due to lower benefits of depletion deductions from our gas reserves activity.

FINANCIAL CONDITION

Capital Structure

One of our long-term goals is to maintain a strong consolidated capital structure with a long-term target utility capital structure of 50% common stock and 50% long-term debt. When additional capital is required, debt or equity securities are issued depending on both the target capital structure and market conditions. These sources of capital are also used to fund long-term debt retirements and short-term commercial paper maturities. See "*Liquidity and Capital Resources*" below and Note 7.

Achieving the target capital structure and maintaining sufficient liquidity to meet operating requirements are necessary to maintain attractive credit ratings and provide access to capital markets at reasonable costs.

Our consolidated capital structure was as follows:

	December 31,	
	2017	2016
Common stock equity	47.1%	52.4%
Long-term debt	43.3	41.9
Short-term debt, including current maturities of long-term debt	9.6	5.7
Total	100.0%	100.0%

During 2017, changes to our capital structure were primarily due to issuances of long-term debt instruments and the impairment of long-lived assets at the Gill Ranch Facility. The net proceeds from the debt issuances will be used for general corporate purposes, primarily to fund our ongoing utility construction programs. See further discussion below in "Cash Flows — *Financing Activities*".

Liquidity and Capital Resources
At both December 31, 2017 and December 31, 2016, we had approximately $3.5 million of cash and cash equivalents. In order to maintain sufficient liquidity during periods when capital markets are volatile, we may elect to maintain higher cash balances and add short-term borrowing capacity. In addition, we may also pre-fund utility capital expenditures when long-term fixed rate environments are attractive. As a regulated entity, our issuance of equity securities and most forms of debt securities are subject to approval by the OPUC and WUTC. Our use of retained earnings is not subject to those same restrictions.

Utility Segment
For the utility segment, the short-term borrowing requirements typically peak during colder winter months when the utility borrows money to cover the lag between natural gas purchases and bill collections from customers. Our short-term liquidity for the utility is primarily provided by cash balances, internal cash flow from operations, proceeds from the sale of commercial paper notes, as well as available cash from multi-year credit facilities, short-term credit facilities, company-owned life insurance policies, the sale of long-term debt, and issuances of equity. Utility long-term debt and equity issuance proceeds are primarily used to finance utility capital expenditures, refinance maturing debt of the utility, and provide temporary funding for other general corporate purposes of the utility.

Based on our current debt ratings (see "*Credit Ratings*" below), we have been able to issue commercial paper and long-term debt at attractive rates and have not needed to borrow or issue letters of credit from our back-up credit facility. In the event we are not able to issue new debt due to adverse market conditions or other reasons, we expect our near-term liquidity needs can be met using internal cash flows or, for the utility segment, drawing upon our committed credit facility. We also have a universal shelf registration statement filed with the SEC for the issuance of secured and unsecured debt or equity securities, subject to market conditions and certain regulatory approvals. As of December 31, 2017, we have Board authorization to issue up to $75 million of additional FMBs. We also have OPUC approval to issue up to $75 million of additional long-term debt for approved purposes.

Our issuance of FMBs, which includes our medium-term notes, under our mortgage and deed of trust is limited by eligible properties, satisfaction of an adjusted net earnings test, and other provisions of the mortgage. The non-cash impairment of long-lived assets at the Gill Ranch Facility is expected to result in our inability to satisfy the earnings test throughout most of 2018. However, we are permitted to issue FMBs without meeting the earnings test on the basis of the $97.0 million of FMBs which will mature in 2018, an amount that is sufficient to accommodate our expected issuances of FMBs in 2018. There is no similar restriction on our ability to issue unsecured long-term debt.

In the event our senior unsecured long-term debt ratings are downgraded, or our outstanding derivative position exceeds a certain credit threshold, our counterparties under derivative contracts could require us to post cash, a letter of credit, or other forms of collateral, which could expose us to additional cash requirements and may trigger increases in short-term borrowings while we were in a net loss position. We were not required to post collateral at December 31, 2017. However, if the credit risk-related contingent features underlying these contracts were triggered on December 31, 2017, assuming our long-term debt ratings dropped to non-investment grade levels, we could have been required to post $15.4 million in collateral with our counterparties. See "*Credit Ratings*" below and Note 13.

Other items that may have a significant impact on our liquidity and capital resources include pension contribution requirements and environmental expenditures.

PENSION CONTRIBUTION. We expect to make significant contributions to our company-sponsored defined benefit plan, which is closed to new employees, over the next several years until we are fully funded under the Pension Protection Act rules, including the new rules issued under the Moving Ahead for Progress in the 21st Century Act (MAP-21) and the Highway and Transportation Funding Act of 2014 (HATFA). See "Application of Critical Accounting Policies—*Accounting for Pensions and Postretirement Benefits*" below.

BONUS DEPRECIATION. Regarding income tax, 50 percent bonus depreciation was available for a large portion of our capital expenditures in 2015, 2016 and most of 2017 for both federal and Oregon. This reduced taxable income and provided cash flow benefits. However, due to the enactment of TCJA on December 22, 2017, bonus depreciation is eliminated for property acquired after September 27, 2017. Accordingly, we do not anticipate similar cash flow benefits related to bonus depreciation in the future.

ENVIRONMENTAL EXPENDITURES. Concerning environmental expenditures, we expect to continue using cash resources to fund our environmental liabilities. In 2015, we received an Order from the OPUC regarding our SRRM and began recovering amounts through utility rates in November 2015. In addition, the OPUC issued a subsequent Order regarding SRRM implementation in January 2016. See Note 15, and "Results of Operations—Regulatory Matters—*Environmental Costs*" above.

GAS STORAGE. Short-term liquidity for the gas storage segment is supported by cash balances, internal cash flow from operations, equity contributions from its parent company, and, if necessary, additional external financing.

The amount and timing of the Gill Ranch Facility's cash flows from year to year are uncertain, as the majority of current storage contracts are short-term. In the fourth quarter of 2017, we recognized a non-cash pretax impairment of long-lived assets at the Gill Ranch Facility of $192.5 million, which is included in our gas storage segment. As a result of the impairment considerations, estimated cash flows from the Gill Ranch Facility were re-evaluated, and although determined no longer sufficient to cover the carrying value of the assets, we do not anticipate material changes in our ability to access sources of cash for short-term liquidity.

CONSOLIDATED LIQUIDITY. Based on several factors, including our current credit ratings, our commercial paper program, current cash reserves, committed credit facilities, and our expected ability to issue long-term debt in the capital markets, we believe our liquidity is sufficient to meet anticipated near-term cash requirements, including all contractual obligations, investing, and financing activities as discussed in *Contractual Obligations* and *Cash Flows* below.

DIVIDEND POLICY. We have paid quarterly dividends on our common stock each year since stock was first issued to the public in 1951. Annual common stock dividend payments per share, adjusted for stock splits, have increased each year since 1956. The declarations and amount of future dividends will depend upon our earnings, cash flows, financial condition and other factors. The amount and timing of dividends payable on our common stock is at the sole discretion of our Board of Directors.

OFF-BALANCE SHEET ARRANGEMENTS. Except for certain lease and purchase commitments, we have no material off-balance sheet financing arrangements. See "*Contractual Obligations"* below.

In October 2017, we entered into a 20-year operating lease agreement for our new headquarters location in Portland, Oregon. Our existing headquarters lease expires in 2020 and after an extensive search and evaluation process with a focus on seismic preparedness, safety, reliability, least cost to our customers and a continued commitment to our employees and the communities we serve, we executed a new lease for suitable commercial office space in Portland, Oregon. Payments under the lease are expected to commence in 2020 and total estimated base rent payments over the life of the lease are approximately $160 million. We have the option to extend the term of the lease for two additional seven-year periods.

Additionally, the lease was analyzed in consideration of build-to-suit lease accounting guidance, and we concluded that we are the accounting owner of the asset during construction. As a result, we recognized $0.5 million in Property, plant and equipment and an obligation in Other non-current liabilities for the same amount on our consolidated balance sheet at December 31, 2017. In 2018, we expect to recognize an additional $27.0 million associated with the build-to-suit accounting treatment of this lease. These accounting transactions are non-cash in nature, and as such, are not included in our cash flow analysis and capital expenditures forecasts below, and have no impact on our short-term liquidity. In 2019, pursuant to the new lease standard issued by the FASB, we expect to de-recognize the associated build-to-suit asset and liability as we will not be subject to build-to-suit accounting under the new lease standard.

Contractual Obligations

The following table shows our contractual obligations at December 31, 2017 by maturity and type of obligation:

	Payments Due in Years Ending December 31,						
In millions	2018	2019	2020	2021	2022	Thereafter	Total
Short-term debt maturities	$ 54.2	$ —	$ —	$ —	$ —	$ —	$ 54.2
Long-term debt maturities	97.0	30.0	75.0	60.0	—	524.7	786.7
Interest on long-term debt	36.4	34.7	28.9	27.8	26.1	249.9	403.8
Postretirement benefit payments(1)	25.1	26.0	27.0	28.0	28.6	161.0	295.7
Operating leases	5.4	5.4	6.9	7.5	7.6	169.4	202.2
Gas purchases(2)	63.9	2.7	2.7	2.3	—	—	71.6
Gas pipeline capacity commitments	83.5	82.1	77.0	65.6	60.1	601.8	970.1
Other purchase commitments(3)	12.9	0.9	0.6	0.1	—	—	14.5
Other long-term liabilities(4)	17.3	—	—	—	—	—	17.3
Total	$ 395.7	$ 181.8	$ 218.1	$ 191.3	$ 122.4	$ 1,706.8	$ 2,816.1

(1) Postretirement benefit payments primarily consists of two items: (1) estimated pension and other postretirement plan payments, which are funded by plan assets and future cash contributions, and (2) required payments to the Western States multiemployer pension plan due to our withdrawal from the plan in December 2013. See Note 8.

(2) Gas purchases include contracts which use price formulas tied to monthly index prices. The commitment amounts presented incorporate the December 2017 first of month index price for each supply basin from which gas is purchased. For a summary of gas purchase and gas pipeline capacity commitments, see Note 14.

(3) Other purchase commitments primarily consist of base gas requirements and remaining balances under existing purchase orders.

(4) Other long-term liabilities includes accrued vacation liabilities for management employees and deferred compensation plan liabilities for executives and directors. The timing of these payments are uncertain; however, these payments are unlikely to all occur in the next 12 months.

In addition to known contractual obligations listed in the above table, we have also recognized liabilities for future environmental remediation or action. The exact timing of payments beyond 12 months with respect to those liabilities cannot be reasonably estimated due to numerous uncertainties surrounding the course of environmental remediation and the preliminary nature of site investigations. See Note 15 for a further discussion of environmental remediation cost liabilities.

At December 31, 2017, 629 of our utility employees were members of the Office and Professional Employees International Union (OPEIU) Local No. 11. In May 2014, our union employees ratified a new labor agreement (Joint Accord) that expires on November 30, 2019, and thereafter from year to year unless either party serves notice of its intent to negotiate modifications to the collective bargaining agreement. The remaining terms of Joint Accord include the following items: a scheduled 3% wage increase effective December 1 each year with the potential for up to an additional 3% per year based on wage inflation at or above 4%. The Joint Accord also maintains competitive health benefits, including a 15% to 20% premium cost sharing by employees, a 401(k) contribution of 4% for employees hired after our pension plan was closed on December 31, 2009, and a 401(k) match of 50% of the first 6% of savings, and other flexibility provisions benefiting the Company.

Short-Term Debt

Our primary source of utility short-term liquidity is from the sale of commercial paper and bank loans. In addition to issuing commercial paper or bank loans to meet working capital requirements, including seasonal requirements to finance gas purchases and accounts receivable, short-term debt may also be used to temporarily fund utility capital requirements. Commercial paper and bank loans are periodically refinanced through the sale of long-term debt or equity securities. When we have outstanding commercial paper, which is sold through two commercial banks under an issuing and paying agency agreement, it is supported by one or more unsecured revolving credit facilities. See "*Credit Agreements*" below.

At December 31, 2017 and 2016, our utility had short-term debt outstanding of $54.2 million and $53.3 million, respectively. The effective interest rate on short-term debt outstanding at December 31, 2017 and 2016 was 1.9% and 0.8%, respectively.

Credit Agreements

We have a $300 million credit agreement, with a feature that allows us to request increases in the total commitment amount, up to a maximum of $450 million. The maturity date of the agreement is December 20, 2019.

All lenders under the agreement are major financial institutions with committed balances and investment grade credit ratings as of December 31, 2017 as follows:

In millions	
Lender rating, by category	Loan Commitment
AA/Aa	$ 201,000
A/A1	99,000
Total	$ 300,000

Based on credit market conditions, it is possible one or more lending commitments could be unavailable to us if the lender defaulted due to lack of funds or insolvency; however, we do not believe this risk to be imminent due to the lenders' strong investment-grade credit ratings.

Our credit agreement permits the issuance of letters of credit in an aggregate amount of up to $100 million. The principal amount of borrowings under the credit agreement is due and payable on the maturity date. There were no outstanding balances under this credit agreement at December 31, 2017 or 2016. The credit agreement requires us to maintain a consolidated indebtedness to total capitalization ratio of 70% or less. Failure to comply with this covenant would entitle the lenders to terminate their lending commitments and accelerate the maturity of all amounts outstanding. We were in compliance with this covenant at December 31, 2017 and 2016, with consolidated indebtedness to total capitalization ratios of 52.9% and 47.6%, respectively.

The agreement also requires us to maintain credit ratings with Standard & Poor's (S&P) and Moody's Investors Service, Inc. (Moody's) and notify the lenders of any change in our senior unsecured debt ratings or senior secured debt ratings, as applicable, by such rating agencies. A change in our debt ratings by S&P or Moody's is not an event of default, nor is the maintenance of a specific minimum level of debt rating a condition of drawing upon the credit agreement. Rather, interest rates on any loans outstanding under the credit agreements are tied to debt ratings and therefore, a change in the debt rating would increase or decrease the cost of any loans under the credit agreements when ratings are changed. See "*Credit Ratings"* below.

Credit Ratings

Our credit ratings are a factor of our liquidity, potentially affecting our access to the capital markets including the commercial paper market. Our credit ratings also have an impact on the cost of funds and the need to post collateral under derivative contracts. The following table summarizes our current debt ratings:

	S&P	Moody's
Commercial paper (short-term debt)	A-1	P-2
Senior secured (long-term debt)	AA-	A1
Senior unsecured (long-term debt)	n/a	A3
Corporate credit rating	A+	n/a
Ratings outlook	Stable	Negative

In January 2018, Moody's revised our ratings outlook from "stable" to "negative". This revision was a result of their view of the potential negative impact that TCJA could have on our regulated utility cash flow metrics. We expect the elimination of bonus depreciation on regulated utilities will increase cash taxes in the near term. However, we expect to see a net increase in cash flows as a result of TCJA over the longer term as taxes are a pass through to customers and lower deferred tax liabilities and no bonus depreciation are expected to increase regulatory returns.

The above credit ratings and ratings outlook are dependent upon a number of factors, both qualitative and quantitative, and are subject to change at any time. The disclosure of or reference to these credit ratings is not a recommendation to buy, sell or hold NW Natural securities. Each rating should be evaluated independently of any other rating.

Long-Term Debt

The following debentures were retired:

	Years Ended December 31,		
In millions	2017	2016	2015
Utility First Mortgage Bonds			
4.70% Series B due 2015	$ —	$ —	$ 40
5.15% Series B due 2016	—	25	—
7.00% Series B due 2017	40	—	—
	$ 40	$ 25	$ 40
Subsidiary Debt			
Fixed-rate	$ —	$ —	$ 20
	$ 40	$ 25	$ 60

Cash Flows

Operating Activities

Changes in our operating cash flows are primarily affected by net income or loss, changes in working capital requirements, and other cash and non-cash adjustments to operating results.

Operating activity highlights include:

In millions	2017	2016	2015
Cash provided by operating activities	$ 206.7	$ 222.1	$ 184.7

2017 COMPARED TO 2016. The significant factors contributing to the $15.4 million decrease in cash flows provided by operating activities were as follows:

- a decrease of $21.9 million due to $14.8 million income taxes paid in 2017 compared to a refund of $7.2 million in 2016 as a result of the enactment of bonus depreciation in December 2015;
- a decrease of $5.0 million due to an increase in contributions paid to qualified defined benefit pension plans; and
- a net decrease of $11.4 million from changes in working capital related to receivables, inventories, and accounts payable reflecting colder than average weather in 2017 compared to the prior period; partially offset by
- an increase of $27.3 million in cash flow benefits from changes in deferred gas cost balances primarily due to the $19.4 million gas cost savings credited to customers in 2016 that did not occur in 2017.

2016 COMPARED TO 2015. The significant factors contributing to the $37.5 million increase in operating cash flows provided by operating activities were as follows:

- a net increase of $29.4 million from changes in working capital related to cold weather in December 2016 and its impact on receivables, inventories, and accounts payable; and
- an increase of $27.6 million in tax related accounts primarily due to a federal tax refund and an increase in accrued taxes and net deferred tax liabilities primarily

due to the enactment of bonus depreciation;
- an increase of $17.7 million from increased cash collections from our decoupling mechanism;
- an increase of $9.8 million from collections under the SRRM; partially offset by
- a decrease of $42.1 million from changes in deferred gas cost balances due to lower natural gas prices than those embedded in the PGA, which also resulted in a $19.4 million early credit to customers' bills in June 2016.

During the year ended December 31, 2017, we contributed $19.4 million to our utility's qualified defined benefit pension plan, compared to $14.5 million for 2016 and $14.1 million for 2015. The amount and timing of future contributions will depend on market interest rates and investment returns on the plans' assets. See Note 8.

Bonus depreciation of 50% has been available for federal and Oregon purposes in 2015, 2016 and most of 2017. This reduced taxable income and provided cash flow benefits. Bonus depreciation for 2015 was not enacted until December 18, 2015, and was extended retroactively back to January 1, 2015 of the respective year. As a result, estimated income tax payments were made throughout 2015 without the benefit of bonus depreciation for the year. This delayed the cash flow benefit of bonus depreciation until refunds could be requested and received. We received refunds of federal income tax overpayments of $7.9 million and $2.0 million in during 2016 and 2015, respectively. As a result of TCJA, bonus depreciation was eliminated for property acquired after September 27, 2017. Accordingly, we do not anticipate similar cash flow benefits related to bonus depreciation in the future.

We have lease and purchase commitments relating to our operating activities that are financed with cash flows from operations. For information on cash flow requirements related to leases and other purchase commitments, see "Financial Condition—*Contractual Obligations*" above and Note 14.

Investing Activities

Investing activity highlights include:

In millions	2017	2016	2015
Total cash used in investing activities	$ (214.2)	$ (136.6)	$ (115.3)
Capital expenditures	(213.6)	(139.5)	(118.3)

2017 COMPARED TO 2016. The $77.6 million increase in cash used in investing activities was primarily due to higher capital expenditures primarily related to our North Mist Gas Storage Expansion Project as well as customer growth, system reinforcement, technology, and facilities.

2016 COMPARED TO 2015. The $21.3 million increase in cash used in investing activities was primarily due to higher utility capital expenditures related to improvements at our Newport LNG facility in Oregon, additional infrastructure investments in Clark County, Washington, and capital expenditures for our North Mist gas storage expansion project.

For the five-year period 2018 to 2022, capital expenditures are estimated to be between $750 and $850 million. This includes investments ranging from $650 to $700 million for core utility capital expenditures that will support continued customer growth, distribution system maintenance and improvements, technology investments, and utility gas storage facility maintenance. In addition, the five-year period range includes $20 to $30 million of additional investments to complete the North Mist gas storage expansion in 2018, and investments of $60 to $70 million related to planned upgrades and refurbishments to utility storage facilities and resource centers. Most of the required funds for these investments are expected to be internally generated over the five-year period, with short-term and long-term debt and equity providing liquidity.

Included in the five year period, 2018 utility capital expenditures are estimated to be between $190 and $220 million, including $20 to $30 million to complete the construction of our North Mist gas storage facility expansion. We expect to invest less than $5 million in non-utility capital expenditures for gas storage and other activities during 2018. Additional spend for gas storage and other investments during and after 2018 are expected to be paid from working capital and additional equity contributions from NW Natural as needed.

Financing Activities

Financing activity highlights include:

In millions	2017	2016	2015
Total cash provided by (used in) financing activities	$ 7.4	$ (86.2)	$ (74.7)
Change in short-term debt	0.9	(216.7)	35.3
Change in long-term debt	60.0	125.0	(60.0)
Change in common stock issued, net	—	52.8	—

2017 COMPARED TO 2016. The $93.6 million increase in cash provided by financing activities was primarily due to $217.6 million lower repayments of short-term debt compared to the prior period, partially offset by $65.0 million lower net proceeds from long-term debt activity in 2017 and $52.8 million of common stock proceeds in 2016.

2016 COMPARED TO 2015. The $11.5 million increase in cash used in financing activities was primarily due to higher repayments of short term loans and commercial paper of $252 million, partially offset by proceeds from $150 million of long-term debt issued in December 2016 and $53 million of common stock issued in November 2016, along with a $35 million decrease in repayments of long-term debt as compared to 2015.

Pension Cost and Funding Status of Qualified Retirement Plans

Pension costs are determined in accordance with accounting standards for compensation and retirement benefits. See "Application of Critical Accounting Policies and Estimates – *Accounting for Pensions and Postretirement Benefits*" below. Pension expense for our qualified defined benefit plan, which is allocated between operations and maintenance expenses, capital expenditures, and the deferred regulatory balancing account, totaled $18.1 million in 2017, an increase of $0.8 million from 2016. The fair market value of pension assets in this plan increased to $287.9 million at December 31, 2017 from $257.7 million at December 31, 2016. The increase was due to a return on plan assets of $40.3 million and $19.4 million in employer contributions, offset by benefit payments of $29.5 million.

We make contributions to the company-sponsored qualified defined benefit pension plan based on actuarial assumptions and estimates, tax regulations, and funding requirements under federal law. Our qualified defined benefit pension plan was underfunded by $161.7 million at December 31, 2017. We plan to make contributions during 2018 of $15.5 million. See Note 8 for further pension disclosures.

Ratios of Earnings to Fixed Charges

For the year ended December 31, 2017, our earnings were insufficient to cover our fixed charges by $86.4 million as a result of the non-cash impairment of long-lived assets at the Gill Ranch Facility. For the years ended December 31, 2016 and 2015, our ratios of earnings to fixed charges, computed using the method outlined by the SEC, were 3.39 and 3.00, respectively. For this purpose, earnings consist of net income before income taxes plus fixed charges, and fixed charges consist of interest on all indebtedness, the amortization of debt expense and discount or premium, and the estimated interest portion of rentals charged to income or loss. See Exhibit 12 for the detailed ratio calculation.

Contingent Liabilities

Loss contingencies are recorded as liabilities when it is probable that a liability has been incurred and the amount of the loss is reasonably estimable in accordance with accounting standards for contingencies. See "*Application of Critical Accounting Policies and Estimates*" below. At December 31, 2017, our total estimated liability related to environmental sites is $127.4 million. See Note 15 and "Results of Operations—Regulatory Matters—Rate Mechanisms—*Environmental Costs*" above.

New Accounting Pronouncements

For a description of recent accounting pronouncements that may have an impact on our financial condition, results of operations, or cash flows, see Note 2.

APPLICATION OF CRITICAL ACCOUNTING POLICIES AND ESTIMATES

In preparing our financial statements in accordance with GAAP, management exercises judgment in the selection and application of accounting principles, including making estimates and assumptions that affect reported amounts of assets, liabilities, revenues, expenses, and related disclosures in the financial statements. Management considers our critical accounting policies to be those which are most important to the representation of our financial condition and results of operations and which require management's most difficult and subjective or complex judgments, including accounting estimates that could result in materially different amounts if we reported under different conditions or used different assumptions. Our most critical estimates and judgments include accounting for:

- regulatory accounting;
- revenue recognition;
- derivative instruments and hedging activities;
- pensions and postretirement benefits;
- income taxes;
- environmental contingencies; and
- impairment of long-lived assets.

Management has discussed its current estimates and judgments used in the application of critical accounting policies with the Audit Committee of the Board. Within the context of our critical accounting policies and estimates, management is not aware of any reasonably likely events or circumstances that would result in materially different amounts being reported. For a description of recent accounting pronouncements that could have an impact on our financial condition, results of operations, or cash flows, see Note 2.

Regulatory Accounting

Our utility is regulated by the OPUC and WUTC, which establish the rates and rules governing utility services provided to customers, and, to a certain extent, set forth special accounting treatment for certain regulatory transactions. In general, we use the same accounting principles as non-regulated companies reporting under GAAP. However, authoritative guidance for regulated operations (regulatory accounting) requires different accounting treatment for regulated companies to show the effects of such regulation. For example, we account for the cost of gas using a PGA deferral and cost recovery mechanism, which is submitted for approval annually to the OPUC and WUTC. See "Results of Operations—Regulatory Matters—Rate Mechanisms—*Purchased Gas Adjustment*" above. There are other expenses and revenues that the OPUC or WUTC may require us to defer for recovery or refund in future periods. Regulatory accounting requires us to account for these types of deferred expenses (or deferred revenues) as regulatory assets (or regulatory liabilities) on the balance sheet. When we are allowed to recover these regulatory assets from, or refund regulatory liabilities to, customers, we recognize the expense or revenue on the income statement at the same time we realize the adjustment to amounts included in utility rates charged to customers.

The conditions we must satisfy to adopt the accounting policies and practices of regulatory accounting include:

- an independent regulator sets rates;
- the regulator sets the rates to cover specific costs of delivering service; and
- the service territory lacks competitive pressures to reduce rates below the rates set by the regulator.

Because our utility satisfies all three conditions, we continue to apply regulatory accounting to our utility operations. Future accounting changes, regulatory changes, or changes in the competitive environment could require us to discontinue the application of regulatory accounting for some or all of our regulated businesses. This would require the write-off of those regulatory assets and liabilities that would no longer be probable of recovery from or refund to customers.

Based on current accounting and regulatory competitive conditions, we believe it is reasonable to expect continued application of regulatory accounting for our utility activities. Further, it is reasonable to expect the recovery or refund of our regulatory assets and liabilities at December 31, 2017 through future customer rates. If we should determine all or a portion of these regulatory assets or liabilities no longer meet the criteria for continued application of regulatory accounting, then we would be required to write-off the net unrecoverable balances against earnings in the period such determination is made. The net balance in regulatory asset and liability accounts was a net liability of $217.7 million and a net asset of $10.3 million as of December 31, 2017 and 2016, respectively. See Note 2 for more detail on our regulatory balances.

Revenue Recognition

Utility and non-utility revenues, which are derived primarily from the sale, transportation, and storage of natural gas, are recognized upon the delivery of gas commodity or services rendered to customers.

Accrued Unbilled Revenue

For a description of our policy regarding accrued unbilled revenue for both the utility and non-utility revenues, see Note 2. The following table presents changes in key metrics if the estimated percentage of unbilled volume at December 31 was adjusted up or down by 1%:

	2017	
In millions	Up 1%	Down 1%
Unbilled revenue increase (decrease)	$ 0.6	$ (0.6)
Utility margin increase (decrease)[(1)]	0.1	(0.1)
Net loss increase (decrease)[(1)]	—	—

(1) Includes impact of regulatory mechanisms including decoupling mechanism.

Derivative Instruments and Hedging Activities

Our gas acquisition and hedging policies set forth guidelines for using financial derivative instruments to support prudent risk management strategies. These policies specifically prohibit the use of derivatives for trading or speculative purposes. We enter into financial derivative contracts to hedge a portion of our utility's natural gas sales requirements. These contracts include swaps, options, and combinations of option contracts. We primarily use these derivative financial instruments to manage commodity price variability. A small portion of our derivative hedging strategy involves foreign currency exchange contracts.

Derivative instruments are recorded on our balance sheet at fair value. If certain regulatory conditions are met, then the derivative instrument fair value is recorded together with an offsetting entry to a regulatory asset or liability account pursuant to regulatory accounting, and no unrealized gain or loss is recognized in current income or loss. See Regulatory Accounting above for additional information. The gain or loss from the fair value of a derivative instrument subject to regulatory deferral is included in the recovery from, or refund to, utility customers in future periods. If a derivative contract is not subject to regulatory deferral, then the accounting treatment for unrealized gains and losses is recorded in accordance with accounting standards for derivatives and hedging which is either in current income or loss or in accumulated other comprehensive income or loss (AOCI or AOCL). Our derivative contracts outstanding at December 31, 2017, 2016 and 2015 were measured at fair value using models or other market accepted valuation methodologies derived from observable market data. Our estimate of fair value may change significantly from period-to-period depending on market conditions and prices. These changes may have an impact on our results of operations, but the impact would largely be mitigated due to the majority of our derivative activities being subject to regulatory deferral treatment. For more information on our derivative activity and associated regulatory treatment, see Note 2 and Note 13.

The following table summarizes the amount of losses realized from commodity price transactions for the last three years:

In millions	2017	2016	2015
Net utility loss on:			
Commodity			
Swaps	$ (7.8)	$ (26.9)	$ (37.7)

Realized losses from commodity hedges shown above were recorded as increases to cost of gas and were, or will be, included in our annual PGA rates.

Pensions and Postretirement Benefits

We maintain a qualified non-contributory defined benefit pension plan, non-qualified supplemental pension plans for eligible executive officers and certain key employees, and other postretirement employee benefit plans covering certain non-union employees. We also have a qualified defined contribution plan (Retirement K Savings Plan) for all eligible employees. Only the qualified defined benefit pension plan and Retirement K Savings Plan have plan assets, which are held in qualified trusts to fund the respective retirement benefits. The qualified defined benefit retirement plan for union and non-union employees was closed to new participants several years ago. These plans are not available to employees at any of our subsidiary companies. Non-union and union employees hired or re-hired after December 31, 2006 and 2009, respectively, and employees of NW Natural subsidiaries are provided an enhanced Retirement K Savings Plan benefit. The postretirement Welfare Benefit Plan for non-union employees was also closed to new participants several years ago.

Net periodic pension and postretirement benefit costs (retirement benefit costs) and projected benefit obligations (benefit obligations) are determined using a number of key assumptions including discount rates, rate of compensation increases, retirement ages, mortality rates and an expected long-term return on plan assets. See Note 8.

Accounting standards also require balance sheet recognition of the overfunded or underfunded status of pension and postretirement benefit plans in AOCI or AOCL, net of tax, based on the fair value of plan assets compared to the actuarial value of future benefit obligations. However, the retirement benefit costs related to our qualified defined benefit pension and postretirement benefit plans are generally recovered in utility rates, which are set based on accounting standards for pensions and postretirement benefit expenses. As such, we received approval from the

OPUC to recognize the overfunded or underfunded status as a regulatory asset or regulatory liability based on expected rate recovery, rather than including it as AOCI or AOCL under common equity. See "*Regulatory Accounting"* above and Note 2, "*Industry Regulation"*.

In 2011, we received regulatory approval from the OPUC and began deferring a portion of our pension expense above or below the amount set in rates to a regulatory balancing account on the balance sheet. At December 31, 2017, the cumulative amount deferred for future pension cost recovery was $60.4 million. The regulatory balancing account includes the recognition of accrued interest on the account balance at the utility's authorized rate of return, with the equity portion of this interest being deferred until amounts are collected in rates.

A number of factors, as discussed above, are considered in developing pension and postretirement benefit assumptions. For the December 31, 2017 measurement date, we reviewed and updated:

- our weighted-average discount rate assumptions for pensions decreased from 4.00% for 2016 to 3.52% for 2017, and our weighted-average discount rate assumptions for other postretirement benefits decreased from 3.85% for 2016 to 3.44% for 2017. The new rate assumptions were determined for each plan based on a matching of benchmark interest rates to the estimated cash flows, which reflect the timing and amount of future benefit payments. Benchmark interest rates are drawn from the Citigroup Above Median Curve, which consists of high quality bonds rated AA- or higher by S&P or Aa3 or higher by Moody's;
- our expected annual rate of future compensation increases, which remained unchanged at a range of 3.25% to 4.5% at December 31, 2017;
- our expected long-term return on qualified defined benefit plan assets, which remained unchanged at a rate of 7.50%;
- our mortality rate assumptions were updated from RP-2006 mortality tables for employees and healthy annuitants with a fully generational projection using scale MP-2016 to corresponding RP-2006 mortality tables using scale MP-2017, which partially offset increases of our projected benefit obligation;
- other key assumptions, which were based on actual plan experience and actuarial recommendations.

At December 31, 2017, our net pension liability (benefit obligations less market value of plan assets) for the qualified defined benefit plan decreased $4.1 million compared to 2016. The decrease in our net pension liability is primarily due to the $26.2 million increase in our pension benefit obligation, offset by an increase of $30.2 million in plan assets. The liability for non-qualified plans increased $2.3 million, and the liability for other postretirement benefits decreased $0.5 million in 2017.

We determine the expected long-term rate of return on plan assets by averaging the expected earnings for the target asset portfolio. In developing our expected return, we analyze historical actual performance and long-term return projections, which gives consideration to the current asset mix and our target asset allocation.

We believe our pension assumptions to be appropriate based on plan design and an assessment of market conditions. However, the following shows the sensitivity of our retirement benefit costs and benefit obligations to changes in certain actuarial assumptions:

Dollars in millions	Change in Assumption	Impact on 2017 Retirement Benefit Costs	Impact on Retirement Benefit Obligations at Dec. 31, 2017
Discount rate:	(0.25)%		
Qualified defined benefit plans		$ 1.4	$ 15.2
Non-qualified plans		—	0.9
Other postretirement benefits		—	0.8
Expected long-term return on plan assets:	(0.25)		
Qualified defined benefit plans		0.7	N/A

In July 2012, President Obama signed into law the MAP-21 Act. This legislation changed several provisions affecting pension plans, including temporary funding relief and Pension Benefit Guaranty Corporation (PBGC) premium increases, which reduces the level of minimum required contributions in the near-term but generally increases contributions in the long-run as well as increasing the operational costs of running a pension plan. Prior to the MAP-21 Act, we were using interest rates based on a 24-month average yield of investment grade corporate bonds (also referred to as "segment rate") to calculate minimum contribution requirements. MAP-21 Act established a new minimum and maximum corridor for segment rates based on a 25-year average of bond yields, which is to be used in calculating contribution requirements. In August 2014, HATFA was signed and extends certain aspects of MAP-21 as well as modifies the phase-out periods for the limitations. As a result we anticipate lower contributions over the next five years with contributions increasing thereafter.

Income Taxes

Valuation Allowances

We recognize deferred tax assets to the extent that we believe these assets are more likely than not to be realized. In making such a determination, we consider the available positive and negative evidence, including future reversals of existing taxable temporary differences, projected future taxable income, tax-planning strategies, and results of recent operations. We have determined that we are more likely than not to realize all recorded deferred tax assets as of December 31, 2017. See Note 9.

Uncertain Tax Benefits

The calculation of our tax liabilities involves dealing with uncertainties in the application of complex tax laws and regulations in the jurisdictions in which we operate. A tax benefit from a material uncertain tax position will only be recognized when it is more likely than not that the position, or some portion thereof, will be sustained upon examination, including resolution of any related appeals or litigation processes, on the basis of the technical merits. We participate in the Compliance Assurance Process (CAP) with the Internal Revenue Service (IRS). Under the CAP program the Company works with the IRS to identify and resolve material tax matters before the federal income tax return is filed each year. No reserves for uncertain tax benefits were recorded during 2017, 2016, or 2015. See Note 9.

Tax Legislation

When significant proposed or enacted changes in income tax rules occur we consider whether there may be a material impact to our financial position, results of operations, cash flows, or whether the changes could materially affect existing assumptions used in making estimates of tax related balances.

On December 22, 2017, H.R.1 - An Act to provide for reconciliation pursuant to titles II and V of the concurrent resolution on the budget for fiscal year 2018, also known as the Tax Cuts and Jobs Act (TCJA), was enacted. The TCJA permanently lowers the U.S. federal corporate income tax rate to 21% from the existing maximum rate of 35%, effective for our tax year beginning January 1, 2018. The TCJA includes specific provisions related to regulated public utilities that generally provide for the continued deductibility of interest expense and the elimination of bonus depreciation for property acquired after September 27, 2017. Certain rate normalization requirements for accelerated cost recovery benefits related to regulated plant balances also continue.

The reduced U.S. corporate income tax rate had a material impact on our financial statements in 2017. As a result of the reduction of the U.S. corporate income tax rate to 21%, U.S. GAAP require deferred tax assets and liabilities be revalued as of the date of enactment, with resulting tax effects accounted for in the reporting period of enactment. We recorded a net revaluation of deferred tax asset and liability balances of $196.4 million as of December 31, 2017, utilizing the reduced federal rate of 21% expected to apply when these temporary differences are realized or settled, based upon balances in existence at the date of enactment. This revaluation had no impact on our 2017 cash flows. See Note 9 for more information on how we are impacted by the TCJA.

With respect to other tax legislation, the final tangible property regulations applicable to all taxpayers were issued on September 13, 2013 and were generally effective for taxable years beginning on or after January 1, 2014. In addition, procedural guidance related to the regulations was issued under which taxpayers may make accounting method changes to comply with the regulations. We have evaluated the regulations and do not anticipate any material impact. However, unit-of-property guidance applicable to natural gas distribution networks has not yet been issued and is expected in the near future. We will further evaluate the effect of these regulations after this guidance is issued, but believe our current method is materially consistent with the new regulations and do not expect this additional guidance to have a material effect on our financial statements.

Regulatory Matters

Regulatory tax assets and liabilities are recorded to the extent it is probable they will be recoverable from, or refunded to, customers in future. At December 31, 2017 and 2016, we had net regulatory income tax assets of $21.3 million and $43.0 million, respectively, representing flow-through future rate recovery of deferred tax liabilities resulting from differences in utility plant financial statement and tax basis and utility plant removal costs. These deferred tax liabilities, and the associated regulatory income tax assets, are currently being recovered through customer rates and were reduced by $17.4 million as a result of the TCJA. At December 31, 2017, we had a regulatory income tax asset of $0.9 million representing probable future rate recovery of deferred tax liabilities resulting from the equity portion of AFUDC. This regulatory asset was reduced by $0.8 million as a result of the TCJA.

On December 29, 2017, we filed applications with OPUC and WUTC seeking authorization to defer the overall net benefits of the utility resulting from the TCJA. On the same day, Staff of the OPUC filed an application seeking deferral of changes in our federal tax obligations resulting from the TCJA. On January 8, 2018, the WUTC issued a statement acknowledging receipt of our application and indicating their intention to incorporate the impact into future rate case proceedings.

We have recorded an estimated regulatory liability of $213.7 million as of December 31, 2017, which includes a gross up for income taxes of $56.6 million, for the change in regulated utility deferred taxes as a result of the TCJA. The TCJA includes specific guidance for determining the shortest time period over which the portion of this regulatory liability resulting from accelerated cost recovery of utility plant may accrue to the benefit of customers to avoid incurring federal normalization penalties. However, it is anticipated that until such time that customers receive the direct benefit of this regulatory liability, the balance, net of the additional gross up for income taxes, will continue to provide an indirect benefit to customers by reducing the utility rate base which determines customer rates for service. It is not possible at this time to determine when the final resolution of these regulatory proceedings will occur, and as result, this regulatory liability is classified as non-current.

Utility rates in effect include an allowance to provide for the recovery of the anticipated provision for income taxes incurred as a result of providing regulated services. The provision for income taxes allowance currently in rates includes an allowance for federal income taxes determined by utilizing the pre-TCJA federal corporate income tax rate of 35%. Beginning in 2018, we anticipate that an additional regulatory liability will be recorded reflecting the deferral of a reduction in our provision for income taxes, incurred as a result of providing regulated utility services, due to the newly enacted 21% federal corporate income tax rate.

Environmental Contingencies

We account for environmental liabilities in accordance with accounting standards under the loss contingency guidance when it is probable that a liability has been incurred and the amount of the loss is reasonably estimable. Amounts recorded for environmental contingencies take numerous factors into consideration, including, among other variables, changes in enacted laws, regulatory orders, estimated remediation costs, interest rates, insurance proceeds, participation by other parties, timing of payments, and the input of legal counsel and third-party experts. Accordingly, changes in any of these variables or other factual circumstances could have a material impact on the amounts recorded for our environmental liabilities. For a complete discussion of our environmental policy refer to Note 2. For a discussion of our current environmental sites and liabilities refer to Note 15 and "*Contingent Liabilities"* above. In addition, for information regarding the regulatory treatment of these costs and our regulatory recovery mechanism, see "Results of Operations—Regulatory Matters—Rate Mechanisms—*Environmental Costs*" above.

Impairment of Long-Lived Assets

We review the carrying value of long-lived assets whenever events or changes in circumstances indicate the carrying amount of the assets might not be recoverable. Factors that would necessitate an impairment assessment of long-lived assets include a significant adverse change in the extent or manner in which the asset is used, a significant adverse change in legal factors or business climate that could affect the value of the asset, or a significant decline in the observable market value or expected future cash flows of the asset, among others.

When such factors are present, we assess the recoverability by determining whether the carrying value of the asset will be recovered through expected future cash flows. An asset is determined to be impaired when the carrying value of the asset exceeds the expected undiscounted future cash flows from the use and eventual disposition of the asset. If an impairment is indicated, we record an impairment loss for the difference between the carrying value and the fair value of the long-lived assets. Fair value is estimated using appropriate valuation methodologies, which may include an estimate of discounted cash flows.

In the fourth quarter of 2017, we recognized a non-cash pre-tax impairment of long-lived assets at the Gill Ranch Facility of $192.5 million, which is included in our gas storage segment. We determined circumstances existed that indicated the carrying value of the assets may not be recoverable. Those circumstances included the completion of a comprehensive strategic review process that evaluated various alternatives including a potential sale, as well as contracting for available storage at lower than anticipated values for the coming storage year. Given these considerations, management was required to re-evaluate the estimated cash flows from our interests in the Gill Ranch Facility, and has determined that those estimated cash flows are no longer sufficient to cover the carrying value of the assets.

We used the income approach to estimate fair value, using the estimated future net cash flows. We also compared the results of the income approach to our own recent sale experience and recent market comparable transactions in order to estimate fair value. Many factors and assumptions impact the net cash flows used. The most significant and uncertain estimates included our forecast of gas storage pricing, our ability to successfully identify and contract with higher-value customers in and/or near the northern California market that Gill Ranch serves, and exploring the possibility of providing energy storage services such as compressed gas energy storage (CGES). After completing the strategic evaluation, which included a potential sale in the fourth quarter of 2017, we have lowered our views of a near-term market recovery and have decreased the likelihood associated with contracting with higher-value customers. These changes were the most significant estimates that caused our cash flow projections to decrease to a point where they are no longer sufficient to cover the carrying value of the asset. The current assumptions used in our fair value model include a significant amount of uncertainty in the estimate of future storage values. Although we have not seen the rebound in storage prices that we originally anticipated, we have worked diligently to operate the Gill Ranch Facility efficiently and will continue to evaluate all strategic options for the Gill Ranch Facility. Our assumptions assume a recovery of the storage market in California and an ability to identify and contract with higher-value customers over the next 5 years, however not to the extent previously forecasted.

While many expense assumptions are included in our projected cash flows, the most significant assumption is our estimated cost and timing of complying with the proposed new safety regulations by DOGGR. Although significant, these estimates were not considered to be as impactful to the fair value of the assets as our estimates of the storage revenues referenced above, but are the most significant capital expense assumptions.

Going forward, the two key estimates that could change and negatively impact the value of this asset are changes to the estimated storage revenues and the cost and timing of complying with the new DOGGR regulations. We currently assume some recovery of storage prices and assume that we will be required to comply with the new DOGGR regulations over the next seven years. Additionally, a sale of the asset could have an impact on fair value, should one occur.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to various forms of market risk including commodity supply risk, commodity price risk, interest rate risk, foreign currency risk, credit risk and weather risk. The following describes our exposure to these risks.

Commodity Supply Risk

We enter into spot, short-term, and long-term natural gas supply contracts, along with associated pipeline transportation contracts, to manage our commodity supply risk. Historically, we have arranged for physical delivery of an adequate supply of gas, including gas in our Mist storage and off-system storage facilities, to meet expected requirements of our core utility customers. Our long-term gas supply contracts are primarily index-based and subject to monthly re-pricing, a strategy that is intended to substantially mitigate credit exposure to our physical gas counterparties. Absolute notional amounts under physical gas contracts related to open positions on our derivative instruments were 520.3 million therms and 535.5 million therms as of December 31, 2017 and 2016, respectively.

Commodity Price Risk

Natural gas commodity prices are subject to market fluctuations due to unpredictable factors including weather, pipeline transportation congestion, drilling technologies, market speculation, and other factors that affect supply and demand. We manage commodity price risk with financial swaps and physical gas reserves from a long-term investment in working interests in gas leases operated by Jonah Energy. These financial hedge contracts and gas reserves volumes are generally included in our annual PGA filing for recovery, subject to a regulatory prudence review. Notional amounts under financial derivative contracts were $108.1 million and $123.6 million as of December 31, 2017 and 2016, respectively. The fair value of financial swaps as of December 31, 2017 was an unrealized loss of $22.3 million with future cash outflows of $14.9 million in 2018, $6.0 million in 2019, and $1.4 million in 2020.

Interest Rate Risk

We are exposed to interest rate risk primarily associated with new debt financing needed to fund capital requirements, including future contractual obligations and maturities of long-term and short-term debt. Interest rate risk is primarily managed through the issuance of fixed-rate debt with varying maturities. We may also enter into financial derivative instruments, including interest rate swaps, options and other hedging instruments, to manage and mitigate interest rate exposure. We did not have any interest rate swaps outstanding as of December 31, 2017 or 2016.

Foreign Currency Risk

The costs of certain pipeline and off-system storage services purchased from Canadian suppliers are subject to changes in the value of the Canadian currency in relation to the U.S. currency. Foreign currency forward contracts are used to hedge against fluctuations in exchange rates for our commodity-related demand and reservation charges paid in Canadian dollars. Notional amounts under foreign currency forward contracts were $7.7 million and $7.5 million as of December 31, 2017 and 2016, respectively. If all of the foreign currency forward contracts had been settled on December 31, 2017, a gain of $0.1 million would have been realized. See Note 13.

Credit Risk

Credit Exposure to Natural Gas Suppliers

Certain gas suppliers have either relatively low credit ratings or are not rated by major credit rating agencies. To manage this supply risk, we purchase gas from a number of different suppliers at liquid exchange points. We evaluate and monitor suppliers' creditworthiness and maintain the ability to require additional financial assurances, including deposits, letters of credit, or surety bonds, in case a supplier defaults. In the event of a supplier's failure to deliver contracted volumes of gas, the regulated utility would need to replace those volumes at prevailing market prices, which may be higher or lower than the original transaction prices. We expect these costs would be subject to our PGA sharing mechanism discussed above. Since most of our commodity supply contracts are priced at the daily or monthly market index price tied to liquid exchange points, and we have adequate storage flexibility, we believe it is unlikely a supplier default would have a material adverse effect on our financial condition or results of operations.

Credit Exposure to Financial Derivative Counterparties

Based on estimated fair value at December 31, 2017, our overall credit exposure relating to commodity contracts is considered immaterial as it reflects amounts owed to financial derivative counterparties (see table below). However, changes in natural gas prices could result in counterparties owing us money. Therefore, our financial derivatives policy requires counterparties to have at least an investment-grade credit rating at the time the derivative instrument is entered into and specific limits on the contract amount and duration based on each counterparty's credit rating. Due to potential changes in market conditions and credit concerns, we continue to enforce strong credit requirements. We actively monitor and manage our derivative credit exposure and place counterparties on hold for trading purposes or require cash collateral, letters of credit, or guarantees as circumstances warrant.

The following table summarizes our overall financial swap and option credit exposure, based on estimated fair value, and the corresponding counterparty credit ratings. The table uses credit ratings from S&P and Moody's, reflecting the higher of the S&P or Moody's rating or a middle rating if the entity is split-rated with more than one rating level difference:

	Financial Derivative Position by Credit Rating Unrealized Fair Value Gain (Loss)	
In millions	2017	2016
AA/Aa	$ (9.0)	$ 13.7
A/A	(13.3)	1.7
Total	$ (22.3)	$ 15.4

In most cases, we also mitigate the credit risk of financial derivatives by having master netting arrangements with our counterparties which provide for making or receiving net cash settlements. Generally, transactions of the same type in the same currency that have settlement on the same day with a single counterparty are netted and a single payment is delivered or received depending on which party is due funds.

Additionally, we have master contracts in place with each of our derivative counterparties that include provisions for posting or calling for collateral. Generally, we can obtain cash or marketable securities as collateral with one day's notice. We use various collateral management strategies to reduce liquidity risk. The collateral provisions vary by counterparty but are not expected to result in the significant posting of collateral, if any. We have performed stress tests on the portfolio and concluded the liquidity risk from collateral calls is not material. Our derivative credit exposure is primarily with investment grade counterparties rated AA-/Aa3 or higher. Contracts are diversified across counterparties to reduce credit and liquidity risk.

At December 31, 2017, our financial derivative credit risk on a volumetric basis was geographically concentrated 36% in the United States and 64% in Canada, based on our counterparties' location. At December 31, 2016, our financial derivative credit risk on a volumetric basis was geographically concentrated 29% in the United States and 71% in Canada with our counterparties.

Credit Exposure to Insurance Companies

Our credit exposure to insurance companies for loss or damage claims could be material. We regularly monitor the financial condition of insurance companies who provide general liability insurance policy coverage to NW Natural and its predecessors.

Weather Risk

We have a weather normalization mechanism in Oregon; however, we are exposed to weather risk primarily from our regulated utility business. A large percentage of our utility margin is volume driven, and current rates are based on an assumption of average weather. Our weather normalization mechanism in Oregon is for residential and commercial customers, which is intended to stabilize the recovery of our utility's fixed costs and reduce fluctuations in customers' bills due to colder or warmer than average weather. Customers in Oregon are allowed to opt out of the weather normalization mechanism. As of December 31, 2017, approximately 9% of our Oregon customers had opted out. In addition to the Oregon customers opting out, our Washington residential and commercial customers account for approximately 11% of our total customer base and are not covered by weather normalization. The combination of Oregon and Washington customers not covered by a weather normalization mechanism is 20% of all residential and commercial customers. See "Results of Operations—Regulatory Matters—Rate Mechanisms—*WARM"* above.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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Supplemental Schedules Omitted

All other schedules are omitted because of the absence of the conditions under which they are required or because the required information is included elsewhere in the financial statements.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) or 15d-15(f) under the Securities Exchange Act of 1934, as amended. Our internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles in the United States of America (GAAP). Our internal control over financial reporting includes those policies and procedures that:

(i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions involving company assets;

(ii) provide reasonable assurance that transactions are recorded as necessary to permit the preparation of financial statements in accordance with GAAP, and that receipts and expenditures are being made only in accordance with authorizations of management and the Board of Directors; and

(iii) provide reasonable assurance regarding prevention or timely detection of the unauthorized acquisition, use, or disposition of our assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements or fraud. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of our internal control over financial reporting as of December 31, 2017. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control-Integrated Framework (2013)*.

Based on our assessment and those criteria, management has concluded that we maintained effective internal control over financial reporting as of December 31, 2017.

The effectiveness of internal control over financial reporting as of December 31, 2017 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears in this annual report.

/s/ David H. Anderson
David H. Anderson
President and Chief Executive Officer

/s/ Frank H. Burkhartsmeyer
Frank H. Burkhartsmeyer
Senior Vice President and Chief Financial Officer

February 23, 2018

To the Board of Directors and Shareholders of Northwest Natural Gas Company:

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of Northwest Natural Gas Company and its subsidiaries as of December 31, 2017 and 2016, and the related consolidated statements of comprehensive income (loss), shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2017 including the related notes and financial statement schedule listed in the accompanying index (collectively referred to as the "consolidated financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2017 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the COSO.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express opinions on the Company's consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP

Portland, Oregon
February 23, 2018

We have served as the Company's auditor since 1997.

NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

In thousands, except per share data	Year Ended December 31, 2017	2016	2015
Operating revenues	$ 762,173	$ 675,967	$ 723,791
Operating expenses:			
Cost of gas	324,795	260,588	327,305
Operations and maintenance	165,246	149,974	157,521
Environmental remediation	15,291	13,298	3,513
General taxes	32,012	30,538	30,281
Depreciation and amortization	85,578	82,289	80,923
Impairment expense	192,478	—	—
Total operating expenses	815,400	536,687	599,543
Income (loss) from operations	(53,227)	139,280	124,248
Other income (expense), net	5,348	(543)	7,747
Interest expense, net	38,501	39,128	42,539
Income (loss) before income taxes	(86,380)	99,609	89,456
Income tax expense (benefit)	(30,757)	40,714	35,753
Net income (loss)	(55,623)	58,895	53,703
Other comprehensive income (loss):			
Change in employee benefit plan liability, net of taxes of $735 for 2017, $452 for 2016, and ($988) for 2015	(2,059)	(744)	1,561
Amortization of non-qualified employee benefit plan liability, net of taxes of ($374) for 2017, ($624) for 2016, and ($883) for 2015	572	955	1,353
Comprehensive income (loss)	$ (57,110)	$ 59,106	$ 56,617
Average common shares outstanding:			
Basic	28,669	27,647	27,347
Diluted	28,669	27,779	27,417
Earnings (loss) per share of common stock:			
Basic	$ (1.94)	$ 2.13	$ 1.96
Diluted	(1.94)	2.12	1.96
Dividends declared per share of common stock	1.88	1.87	1.86

See Notes to Consolidated Financial Statements

NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED BALANCE SHEETS

In thousands	As of December 31, 2017	2016
Assets:		
Current assets:		
Cash and cash equivalents	$ 3,472	$ 3,521
Accounts receivable	68,362	66,700
Accrued unbilled revenue	62,381	64,946
Allowance for uncollectible accounts	(956)	(1,290)
Regulatory assets	45,781	42,362
Derivative instruments	1,735	17,031
Inventories	47,973	54,129
Gas reserves	15,704	15,926
Other current assets	25,484	24,728
Total current assets	269,936	288,053
Non-current assets:		
Property, plant, and equipment	3,215,451	3,208,816
Less: Accumulated depreciation	960,477	947,916
Total property, plant, and equipment, net	2,254,974	2,260,900
Gas reserves	84,053	100,184
Regulatory assets	356,608	357,530
Derivative instruments	1,306	3,265
Other investments	66,363	68,376
Other non-current assets	6,506	1,493
Total non-current assets	2,769,810	2,791,748
Total assets	$ 3,039,746	$ 3,079,801

See Notes to Consolidated Financial Statements

NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED BALANCE SHEETS

In thousands	As of December 31, 2017	2016
Liabilities and equity:		
Current liabilities:		
Short-term debt	$ 54,200	$ 53,300
Current maturities of long-term debt	96,703	39,989
Accounts payable	112,308	85,664
Taxes accrued	18,883	12,149
Interest accrued	6,773	5,966
Regulatory liabilities	34,013	40,290
Derivative instruments	18,722	1,315
Other current liabilities	40,248	35,844
Total current liabilities	381,850	274,517
Long-term debt	683,184	679,334
Deferred credits and other non-current liabilities:		
Deferred tax liabilities	270,526	557,085
Regulatory liabilities	586,093	349,319
Pension and other postretirement benefit liabilities	223,333	225,725
Derivative instruments	4,649	913
Other non-current liabilities	147,335	142,411
Total deferred credits and other non-current liabilities	1,231,936	1,275,453
Commitments and contingencies (see Note 14 and Note 15)		
Equity:		
Common stock - no par value; authorized 100,000 shares; issued and outstanding 28,736 and 28,630 at December 31, 2017 and 2016, respectively	448,865	445,187
Retained earnings	302,349	412,261
Accumulated other comprehensive loss	(8,438)	(6,951)
Total equity	742,776	850,497
Total liabilities and equity	$ 3,039,746	$ 3,079,801

See Notes to Consolidated Financial Statements

NORTHWEST NATURAL GAS COMPANY

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

In thousands	Common Stock	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Equity
Balance at December 31, 2014	$ 375,117	$ 402,280	$ (10,076)	$ 767,321
Comprehensive income	—	53,703	2,914	56,617
Dividends on common stock	—	(50,993)	—	(50,993)
Tax expense from employee stock plans	(118)	—	—	(118)
Stock-based compensation	3,277	—	—	3,277
Shares issued pursuant to equity based plans	4,868	—	—	4,868
Balance at December 31, 2015	383,144	404,990	(7,162)	780,972
Comprehensive income	—	58,895	211	59,106
Dividends on common stock	—	(51,624)	—	(51,624)
Stock-based compensation	2,924	—	—	2,924
Shares issued pursuant to equity based plans	6,358	—	—	6,358
Issuance of common stock, net of issuance costs	52,761	—	—	52,761
Balance at December 31, 2016	445,187	412,261	(6,951)	850,497
Comprehensive income (loss)	—	(55,623)	(1,487)	(57,110)
Dividends on common stock	—	(54,289)	—	(54,289)
Stock-based compensation	2,882	—	—	2,882
Shares issued pursuant to equity based plans	796	—	—	796
Balance at December 31, 2017	$ 448,865	$ 302,349	$ (8,438)	$ 742,776

See Notes to Consolidated Financial Statements

NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS

In thousands	Year Ended December 31, 2017	2016	2015
Operating activities:			
Net income (loss)	$ (55,623)	$ 58,895	$ 53,703
Adjustments to reconcile net income (loss) to cash provided by operations:			
Depreciation and amortization	85,578	82,289	80,923
Regulatory amortization of gas reserves	16,353	15,525	17,991
Deferred income taxes	(52,414)	32,056	26,972
Qualified defined benefit pension plan expense	5,364	5,274	5,697
Contributions to qualified defined benefit pension plans	(19,430)	(14,470)	(14,120)
Deferred environmental expenditures, net	(13,716)	(10,469)	(10,568)
Regulatory disallowance of prior environmental cost deferrals	—	3,287	15,000
Amortization of environmental remediation	15,291	13,298	3,513
Impairment of long-lived assets	192,478	—	—
Other	2,127	3,225	(1,613)
Changes in assets and liabilities:			
Receivables, net	3,099	(7,484)	2,373
Inventories	5,571	16,620	6,964
Income taxes	6,734	9,467	(6,541)
Accounts payable	1,424	12,380	(17,175)
Interest accrued	807	93	(206)
Deferred gas costs	17,122	(10,204)	31,918
Other, net	(4,061)	12,365	(10,143)
Cash provided by operating activities	206,704	222,147	184,688
Investing activities:			
Capital expenditures	(213,595)	(139,511)	(118,320)
Other	(577)	2,882	3,022
Cash used in investing activities	(214,172)	(136,629)	(115,298)
Financing activities:			
Repurchases related to stock-based compensation	(2,034)	(1,042)	—
Proceeds from stock options exercised	4,819	8,404	3,875
Proceeds from common stock issued	—	52,760	—
Long-term debt issued	100,000	150,000	—
Long-term debt retired	(40,000)	(25,000)	(60,000)
Change in short-term debt	900	(216,735)	35,335
Cash dividend payments on common stock	(53,957)	(51,508)	(49,243)
Other	(2,309)	(3,087)	(4,680)
Cash provided by (used in) financing activities	7,419	(86,208)	(74,713)
(Decrease) increase in cash and cash equivalents	(49)	(690)	(5,323)
Cash and cash equivalents, beginning of period	3,521	4,211	9,534
Cash and cash equivalents, end of period	$ 3,472	$ 3,521	$ 4,211
Supplemental disclosure of cash flow information:			
Interest paid, net of capitalization	$ 34,787	$ 36,023	$ 39,634
Income taxes paid (refunded)	14,780	(7,157)	17,306

See Notes to Consolidated Financial Statements

NORTHWEST NATURAL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION AND PRINCIPLES OF CONSOLIDATION

The accompanying consolidated financial statements represent the consolidated results of Northwest Natural Gas Company (NW Natural or the Company) and all companies we directly or indirectly control, either through majority ownership or otherwise. We have two core businesses: our regulated local gas distribution business, referred to as the utility segment, which serves residential, commercial, and industrial customers in Oregon and southwest Washington; and our gas storage businesses, referred to as the gas storage segment, which provides storage services for utilities, gas marketers, electric generators, and large industrial users from facilities located in Oregon and California. In addition, we have investments and other non-utility activities we aggregate and report as other.

Our core utility business assets and operating activities are largely included in the parent company, NW Natural. Our direct and indirect wholly-owned subsidiaries include NW Natural Energy, LLC (NWN Energy), NW Natural Gas Storage, LLC (NWN Gas Storage), Gill Ranch Storage, LLC (Gill Ranch), NNG Financial Corporation (NNG Financial), Northwest Energy Corporation (Energy Corp), Northwest Natural Water Company (NWN Water), FWC Merger Sub, Inc., and NWN Gas Reserves LLC (NWN Gas Reserves). Investments in corporate joint ventures and partnerships we do not directly or indirectly control, and for which we are not the primary beneficiary, include NWN Financial's investment in Kelso-Beaver Pipeline and NWN Energy's investment in Trail West Holdings, LLC (TWH), which is accounted for under the equity method. NW Natural and its affiliated companies are collectively referred to herein as NW Natural. The consolidated financial statements are presented after elimination of all intercompany balances and transactions. In this report, the term “utility” is used to describe our regulated gas distribution business, and the term “non-utility” is used to describe our gas storage businesses and other non-utility investments and business activities.

Certain prior year balances in our consolidated financial statements and notes have been reclassified to conform with the current presentation. These reclassifications had no effect on our prior year’s consolidated results of operations, financial condition, or cash flows.

2. SIGNIFICANT ACCOUNTING POLICIES

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles in the United States of America (GAAP) requires management to make estimates and assumptions that affect reported amounts in the consolidated financial statements and accompanying notes. Actual amounts could differ from those estimates, and changes would most likely be reported in future periods. Management believes the estimates and assumptions used are reasonable.

Industry Regulation

Our principal businesses are the distribution of natural gas, which is regulated by the OPUC and WUTC, and natural gas storage services, which are regulated by either the FERC or the CPUC, and to a certain extent by the OPUC and WUTC. Accounting records and practices of our regulated businesses conform to the requirements and uniform system of accounts prescribed by these regulatory authorities in accordance with U.S. GAAP. Our businesses regulated by the OPUC, WUTC, and FERC earn a reasonable return on invested capital from approved cost-based rates, while our business regulated by the CPUC earns a return to the extent we are able to charge competitive prices above our costs (i.e. market-based rates).

In applying regulatory accounting principles, we capitalize or defer certain costs and revenues as regulatory assets and liabilities pursuant to orders of the OPUC or WUTC, which provide for the recovery of revenues or expenses from, or refunds to, utility customers in future periods, including a return or a carrying charge in certain cases.

At December 31, the amounts deferred as regulatory assets and liabilities were as follows:

	Regulatory Assets	
In thousands	2017	2016
Current:		
Unrealized loss on derivatives(1)	$ 18,712	$ 1,315
Gas costs	154	6,830
Environmental costs(2)	6,198	9,989
Decoupling(3)	11,227	13,067
Income taxes	2,218	4,378
Other(4)	7,272	6,783
Total current	$ 45,781	$ 42,362
Non-current:		
Unrealized loss on derivatives(1)	$ 4,649	$ 913
Pension balancing(5)	60,383	50,863
Income taxes	19,991	38,670
Pension and other postretirement benefit liabilities	179,824	183,035
Environmental costs(2)	72,128	63,970
Gas costs	84	89
Decoupling(3)	3,970	5,860
Other(4)	15,579	14,130
Total non-current	$ 356,608	$ 357,530

In thousands	Regulatory Liabilities 2017	2016
Current:		
Gas costs	$ 14,886	$ 8,054
Unrealized gain on derivatives(1)	1,674	16,624
Decoupling(3)	322	—
Other(4)	17,131	15,612
Total current	$ 34,013	$ 40,290
Non-current:		
Gas costs	$ 4,630	$ 1,021
Unrealized gain on derivatives(1)	1,306	3,265
Decoupling(3)	957	—
Income taxes	213,306	—
Accrued asset removal costs(6)	360,929	341,107
Other(4)	4,965	3,926
Total non-current	$ 586,093	$ 349,319

(1) Unrealized gains or losses on derivatives are non-cash items and, therefore, do not earn a rate of return or a carrying charge. These amounts are recoverable through utility rates as part of the annual Purchased Gas Adjustment (PGA) mechanism when realized at settlement.

(2) Refer to footnote (3) per the Deferred Regulatory Asset table in Note 15 for a description of environmental costs.

(3) This deferral represents the margin adjustment resulting from differences between actual and expected volumes.

(4) These balances primarily consist of deferrals and amortizations under approved regulatory mechanisms. The accounts being amortized typically earn a rate of return or carrying charge.

(5) Refer to footnote (1) of the Net Periodic Benefit Cost table per Note 8 for information regarding the deferral of pension expenses.

(6) Estimated costs of removal on certain regulated properties are collected through rates. See "Accounting Policies—*Plant, Property, and Accrued Asset Removal Costs*" below.

The amortization period for our regulatory assets and liabilities ranges from less than one year to an indeterminable period. Our regulatory deferrals for gas costs payable are generally amortized over 12 months beginning each November 1 following the gas contract year during which the deferred gas costs are recorded. Similarly, most of our other regulatory deferred accounts are amortized over 12 months. However, certain regulatory account balances, such as income taxes, environmental costs, pension liabilities, and accrued asset removal costs, are large and tend to be amortized over longer periods once we have agreed upon an amortization period with the respective regulatory agency.

We believe all costs incurred and deferred at December 31, 2017 are prudent. We annually review all regulatory assets and liabilities for recoverability and more often if circumstances warrant. If we should determine that all or a portion of these regulatory assets or liabilities no longer meet the criteria for continued application of regulatory accounting, we would be required to write-off the net unrecoverable balances in the period such determination is made.

Environmental Regulatory Accounting

See Note 15 for information about our SRRM and OPUC orders regarding implementation.

New Accounting Standards

We consider the applicability and impact of all accounting standards updates (ASUs) issued by the Financial Accounting Standards Board (FASB). Accounting standards updates not listed below were assessed and determined to be either not applicable or are expected to have minimal impact on our consolidated financial position or results of operations.

Recently Issued Accounting Pronouncements

DERIVATIVES AND HEDGING. On August 28, 2017, the FASB issued ASU 2017-12, "Derivatives and Hedging: Targeted Improvements to Accounting for Hedging Activities." The purpose of the amendment is to more closely align hedge accounting with companies' risk management strategies. The ASU amends the accounting for risk component hedging, the hedged item in fair value hedges of interest rate risk, and amounts excluded from the assessment of hedge effectiveness. The guidance also amends the recognition and presentation of the effect of hedging instruments and includes other simplifications of hedge accounting. The amendments in this update are effective for us beginning January 1, 2019. Early adoption is permitted. The amended presentation and disclosure guidance is required prospectively. We are currently assessing the effect of this standard on our financial statements and disclosures.

STOCK COMPENSATION. On May 10, 2017, the FASB issued ASU 2017-09, "Stock Compensation - Scope of Modification Accounting." The purpose of the amendment is to provide clarity, reduce diversity in practice and reduce the cost and complexity when applying the guidance in ASC 718, related to a change to the terms or conditions of a share-based payment award. The ASU amends the scope of modification accounting for share-based payment arrangements and provides guidance on the types of changes to the terms or conditions of share-based payment awards to which an entity would be required to apply modification accounting under ASC 718. Specifically, an entity would not apply modification accounting if the fair value, vesting conditions, and classification of the awards are the same immediately before and after the modification. The amendments in this update are effective for us beginning January 1, 2018. The amendments in this update should be applied prospectively to an award modified on or after the adoption date. We do not expect this standard to materially affect our financial statements and disclosures.

RETIREMENT BENEFITS. On March 10, 2017, the FASB issued ASU 2017-07, "Improving the Presentation of Net Periodic Pension Cost and Net Periodic Post Retirement Benefit Cost." The ASU requires entities to disaggregate current service cost from the other components of net periodic benefit cost and present it with other current compensation costs for related employees in the income statement and to present the other components elsewhere in the income statement and outside of income from operations if that subtotal is presented. Only the service cost component of the net periodic benefit cost is eligible for capitalization. The amendments in this update are effective for us beginning January 1, 2018. Upon adoption, the ASU requires that changes to the income statement presentation of net periodic benefit cost be applied retrospectively, while changes to amounts capitalized must be applied prospectively. On December 28, 2017, the FERC issued Docket AI18-1-000 stating that it will allow entities to change their capitalization policy for regulatory accounting and reporting purposes to be consistent with the new US GAAP requirements. This change will be allowed as a one-time policy election upon adoption of the guidance. We have elected to adopt the new ASU for FERC regulatory accounting and reporting purposes. We anticipate that this adoption will reduce amounts capitalized to plant. However, this reduction will be largely offset by deferrals to our pension regulatory balancing mechanism, and therefore, we do not expect this standard to materially affect our financial position.

STATEMENT OF CASH FLOWS. On August 26, 2016, the FASB issued ASU 2016-15, "Classification of Certain Cash Receipts and Cash Payments." The ASU adds guidance pertaining to the classification of certain cash receipts and payments on the statement of cash flows. The purpose of the amendment is to clarify issues that have been creating diversity in practice, including the classification of proceeds from the settlement of insurance claims and proceeds from the settlement of corporate-owned life insurance policies. The amendments in this standard are effective for us beginning January 1, 2018. We do not expect this standard to materially affect our financial statements and disclosures.

LEASES. On February 25, 2016, the FASB issued ASU 2016-02, "Leases," which revises the existing lease accounting guidance. Pursuant to the new standard, lessees will be required to recognize all leases, including operating leases that are greater than 12 months at lease commencement, on the balance sheet and record corresponding right-of-use assets and lease liabilities. Lessor accounting will remain substantially the same under the new standard. Quantitative and qualitative disclosures are also required for users of the financial statements to have a clear understanding of the nature of our leasing activities. The standard is effective for us beginning January 1, 2019. The new standard must be adopted using a modified retrospective transition and provides for certain practical expedients. On November 29, 2017, the FASB proposed an additional practical expedient that would allow entities to apply the transition requirements on the effective date of the standard.

On January 25, 2018, the FASB issued ASU 2018-01, "Land Easement Practical Expedient for Transition to Topic 842", to address the costs and complexity of applying the transition provisions of the new lease standard to land easements. This ASU provides an optional practical expedient to not evaluate existing or expired land easements that were not previously accounted for as leases under the current lease guidance.

We are evaluating additional amendments reached by the FASB, and we are currently assessing our lease population and material contracts to determine the effect of this standard on our financial statements and disclosures. Refer to Note 14 for our current lease commitments.

FINANCIAL INSTRUMENTS. On January 5, 2016, the FASB issued ASU 2016-01, "Financial Instruments - Overall: Recognition and Measurement of Financial Assets and Financial Liabilities." The ASU enhances the reporting model for financial instruments, which includes amendments to address aspects of recognition, measurement, presentation, and disclosure. The new standard is effective for us beginning January 1, 2018. Any impacts as a result of the implementation of this ASU will be made through a cumulative-effect adjustment to the consolidated balance sheet in the first quarter of 2018. We do not expect this standard to have a material impact to our financial statements and disclosures.

REVENUE RECOGNITION. On May 28, 2014, the FASB issued ASU 2014-09 "Revenue From Contracts with Customers." Subsequently, the FASB issued additional, clarifying amendments to address issues and questions regarding implementation of the new revenue recognition standard. The underlying principle of the guidance requires entities to recognize revenue depicting the transfer of goods or services to customers at amounts the entity is expected to be entitled to in exchange for those goods or services. The ASU also prescribes a five-step approach to revenue recognition: (1) identify the contract(s) with the customer; (2) identify the separate performance obligations in the contract(s); (3) determine the transaction price; (4) allocate the transaction price to separate performance obligations; and (5) recognize revenue when, or as, each performance obligation is satisfied. The guidance also requires additional disclosures, both qualitative and quantitative, regarding the nature, amount, timing and uncertainty of revenue and cash flows. The new requirements prescribe either a full retrospective or modified retrospective adoption method. The new standard is effective for us beginning January 1, 2018, and we have elected to adopt the standard using the modified retrospective approach. We are in the process of updating our accounting policies, processes, systems, and internal controls as a result of implementing the new standard. We have analyzed our revenue streams, material contracts with customers, and the expanded disclosure requirements under the new standard and determined that the standard will not have a material impact on our financial position, net income, or cash flows.

Accounting Policies

Plant, Property, and Accrued Asset Removal Costs

Plant and property are stated at cost, including capitalized labor, materials, and overhead. In accordance with regulatory accounting standards, the cost of acquiring and constructing long-lived plant and property generally includes an allowance for funds used during construction (AFUDC) or capitalized interest. AFUDC represents the regulatory financing cost incurred when debt and equity funds are used for construction (see "*AFUDC*" below). When constructed assets are subject to market-based rates rather than cost-based rates, the financing costs incurred during construction are included in capitalized interest in accordance with U.S. GAAP, not as regulatory financing costs under AFUDC.

In accordance with long-standing regulatory treatment, our depreciation rates consist of three components: one based on the average service life of the asset, a second based on the estimated salvage value of the asset, and a third based on the asset's estimated cost of removal. We collect, through rates, the estimated cost of removal on certain regulated properties through depreciation expense, with a corresponding offset to accumulated depreciation. These removal costs are non-legal obligations as defined by regulatory accounting guidance. Therefore, we have included these costs as non-current regulatory liabilities rather than as accumulated depreciation on our consolidated balance sheets. In the rate setting process, the liability for removal costs is treated as a reduction to the net rate base on which the regulated utility has the opportunity to earn its allowed rate of return.

The costs of utility plant retired or otherwise disposed of are removed from utility plant and charged to accumulated depreciation for recovery or refund through future rates. Gains from the sale of regulated assets are generally deferred and refunded to customers. For non-utility assets, we record a gain or loss upon the disposal of the property, and the gain or loss is recorded in operating income or loss in the consolidated statements of comprehensive income or loss.

Our provision for depreciation of utility property, plant, and equipment is recorded under the group method on a straight-line basis with rates computed in accordance with depreciation studies approved by regulatory authorities. The weighted-average depreciation rate for utility assets in service was approximately 2.8% for 2017, 2016, and 2015, reflecting the approximate weighted-average economic life of the property. This includes 2017 weighted-average depreciation rates for the following asset categories: 2.7% for transmission and distribution plant, 2.3% for gas storage facilities, 4.4% for general plant, and 2.7% for intangible and other fixed assets.

AFUDC. Certain additions to utility plant include AFUDC, which represents the net cost of debt and equity funds used during construction. AFUDC is calculated using actual interest rates for debt and authorized rates for ROE, if applicable. If short-term debt balances are less than the total balance of construction work in progress, then a composite AFUDC rate is used to represent interest on all debt funds, shown as a reduction to interest charges, and on ROE funds, shown as other income. While cash is not immediately recognized from recording AFUDC, it is realized in future years through rate recovery resulting from the higher utility cost of service. Our composite AFUDC rate was 5.5% in 2017, 0.7% in 2016, and 0.4% in 2015.

IMPAIRMENT OF LONG-LIVED ASSETS. We review the carrying value of long-lived assets whenever events or changes in circumstances indicate the carrying amount of the assets may not be recoverable. Factors that would necessitate an impairment assessment of long-lived assets include a significant adverse change in the extent or manner in which the asset is used, a significant adverse change in legal factors or business climate that could affect the value of the asset, or a significant decline in the observable market value or expected future cash flows of the asset, among others.

When such factors are present, we assess the recoverability by determining whether the carrying value of the asset will be recovered through expected future cash flows. An asset is determined to be impaired when the carrying value of the asset exceeds the expected undiscounted future cash flows from the use and eventual disposition of the asset. If an impairment is indicated, we record an impairment loss for the difference between the carrying value and the fair value of the long-lived assets. Fair value is estimated using appropriate valuation methodologies, which may include an estimate of discounted cash flows.

In the fourth quarter of 2017, we recognized a non-cash pre-tax impairment of long-lived assets at the Gill Ranch Facility of $192.5 million, which is included in our gas storage segment. We determined circumstances existed that indicated the carrying value of the assets may not be recoverable. Those circumstances included the completion of a comprehensive strategic review process that evaluated various alternatives including a potential sale, as well as contracting for available storage at lower than anticipated values for the coming storage year. Given these considerations, management was required to re-evaluate the estimated cash flows from our interests in the Gill Ranch Facility, and has determined that those estimated cash flows are no longer sufficient to cover the carrying value of the assets. We did not recognize any impairments in 2016 or 2015.

We used the income approach to estimate fair value, using the estimated future net cash flows of the Gill Ranch Facility. We also compared the results of the income approach to our own recent sale process experience and recent market comparable transactions in order to estimate fair value.

Cash and Cash Equivalents

For purposes of reporting cash flows, cash and cash equivalents include cash on hand plus highly liquid investment accounts with original maturity dates of three months or less. At December 31, 2017 and 2016, outstanding checks of approximately $4.8 million and $2.9 million, respectively, were included in accounts payable.

Revenue Recognition and Accrued Unbilled Revenue

Utility revenues, derived primarily from the sale and transportation of natural gas, are recognized upon delivery of the gas commodity or service to customers. Revenues include accruals for gas delivered but not yet billed to customers based on estimates of deliveries from meter reading dates to month end (accrued unbilled revenue). Accrued unbilled revenue is dependent upon a number of factors that require management's judgment, including total gas receipts and deliveries, customer use by billing cycle, and weather factors. Accrued unbilled revenue is reversed the following month when actual billings occur. Our accrued unbilled revenue at December 31, 2017 and 2016 was $62.4 million and $64.9 million, respectively.

Non-utility revenues are derived primarily from the gas storage segment. At our Mist underground storage facility, revenues are primarily firm service revenues in the form of fixed monthly reservation charges. At the Gill Ranch Facility, firm storage services resulting from short-term and long-term contracts are typically recognized in revenue ratably over the term of the contract regardless of the actual storage capacity utilized. In addition, we also have asset management service revenue from an independent energy marketing company that optimizes commodity, storage, and pipeline capacity release transactions. Under this agreement, guaranteed asset management revenue is recognized using a straight-line, pro-rata methodology over the term of each contract. Revenues earned above the guaranteed amount are recognized as they are earned.

Revenue Taxes

Revenue-based taxes are primarily franchise taxes, which are collected from customers and remitted to taxing authorities. Revenue taxes are included in operating revenues in the statement of comprehensive income or loss. Revenue taxes were $19.1 million, $17.1 million, and $18.0 million for 2017, 2016, and 2015, respectively.

Accounts Receivable and Allowance for Uncollectible Accounts

Accounts receivable consist primarily of amounts due for natural gas sales and transportation services to utility customers, plus amounts due for gas storage services. We establish an allowance for uncollectible accounts (allowance) for trade receivables, including accrued unbilled revenue, based on the aging of receivables, collection experience of past due account balances including payment plans, and historical trends of write-offs as a percent of revenues. A specific allowance is established and recorded for large individual customer receivables when amounts are identified as unlikely to be partially or fully recovered. Inactive accounts are written-off against the allowance after they are 120 days past due or when deemed uncollectible. Differences between our estimated allowance and actual write-offs will occur based on a number of factors, including changes in economic conditions, customer creditworthiness, and natural gas prices. The allowance for uncollectible accounts is adjusted quarterly, as necessary, based on information currently available.

Inventories

Utility gas inventories, which consist of natural gas in storage for the utility, are stated at the lower of average cost or net realizable value. The regulatory treatment of utility gas inventories provides for cost recovery in customer rates. Utility gas inventories injected into storage are priced in inventory based on actual purchase costs. Utility gas inventories withdrawn from storage are charged to cost of gas during the current period they are withdrawn at the weighted-average inventory cost.

Gas storage inventories, which primarily represent inventories at the Gill Ranch Facility, mainly consist of natural gas received as fuel-in-kind from storage customers. Gas storage inventories are valued at the lower of average cost or net realizable value. Cushion gas is not included in our inventory balances, is recorded at original cost, and is classified as a long-term plant asset.

Materials and supplies inventories consist of both utility and non-utility inventories and are stated at the lower of average cost or net realizable value.

Our utility and gas storage inventories totaled $36.7 million and $42.7 million at December 31, 2017 and 2016, respectively. At December 31, 2017 and 2016, our materials and supplies inventories totaled $11.3 million and $11.4 million, respectively.

Gas Reserves

Gas reserves are payments to acquire and produce natural gas reserves. Gas reserves are stated at cost, adjusted for regulatory amortization, with the associated deferred tax benefits recorded as liabilities on the balance sheet. The current portion is calculated based on expected gas deliveries within the next fiscal year. We recognize regulatory amortization of this asset on a volumetric basis calculated using the estimated gas reserves and the estimated therms extracted and sold each month. The amortization of gas reserves is recorded to cost of gas along with gas production revenues and production costs. See Note 11.

Derivatives

Derivatives are measured at fair value and recognized as either assets or liabilities on the balance sheet. Changes in the fair value of the derivatives are recognized currently in earnings unless specific regulatory or hedge accounting criteria are met. Accounting for derivatives and hedges provides an exception for contracts intended for normal purchases and normal sales for which physical delivery is probable. In addition, certain derivative contracts are approved by regulatory authorities for recovery or refund through customer rates. Accordingly, the changes in fair value of these approved contracts are deferred as regulatory assets or liabilities pursuant to regulatory accounting principles. Our financial derivatives generally qualify for deferral under regulatory accounting. Our index-priced physical derivative contracts also qualify for regulatory deferral accounting treatment.

Derivative contracts entered into for utility requirements after the annual PGA rate has been set and maturing during the PGA year are subject to the PGA incentive sharing mechanism. In Oregon we participate in a PGA sharing mechanism under which we are required to select either an 80% or 90% deferral of higher or lower gas costs such that the impact on current earnings from the gas cost sharing is either 20% or 10% of gas cost differences compared to PGA prices, respectively. For the PGA years in Oregon beginning November 1, 2017, 2016, and 2015, we selected the 90%, 90%, and 80% deferral of gas cost differences, respectively. In Washington, 100% of the differences between the PGA prices and actual gas costs are deferred. See Note 13.

Our financial derivatives policy sets forth the guidelines for using selected derivative products to support prudent risk management strategies within designated parameters. Our objective for using derivatives is to decrease the volatility of gas prices, earnings, and cash flows without speculative risk. The use of derivatives is permitted only after the risk exposures have been identified, are determined not to exceed acceptable tolerance levels, and are determined necessary to support normal business activities. We do not enter into derivative instruments for trading purposes.

Fair Value

In accordance with fair value accounting, we use the following fair value hierarchy for determining inputs for our debt, pension plan assets, and our derivative fair value measurements:

- Level 1: Valuation is based on quoted prices for identical instruments traded in active markets;
- Level 2: Valuation is based on quoted prices for similar instruments in active markets, quoted prices for identical or similar instruments in markets that are not active, and model-based valuation techniques for which all significant assumptions are observable in the market; and
- Level 3: Valuation is generated from model-based techniques that use significant assumptions not observable in the market. These unobservable assumptions reflect our own estimates of assumptions market participants would use in valuing the asset or liability.

When developing fair value measurements, it is our policy to use quoted market prices whenever available or to maximize the use of observable inputs and minimize the use of unobservable inputs when quoted market prices are not available. Fair values are primarily developed using industry-standard models that consider various inputs including: (a) quoted future prices for commodities; (b) forward currency prices; (c) time value; (d) volatility factors; (e) current market and contractual prices for underlying instruments; (f) market interest rates and yield curves; (g) credit spreads; and (h) other relevant economic measures. The Company considers liquid points for its natural gas hedging to be those points for which there are regularly published prices in a nationally recognized publication or where the instruments are traded on an exchange.

Income Taxes

We account for income taxes under the asset and liability method, which requires the recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been included in the financial statements. Under this method, deferred tax assets and liabilities are determined on the basis of the differences between the financial statement and tax basis of assets and liabilities using enacted tax rates in effect for the year in which the differences are expected to reverse. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the enactment date period unless a regulatory Order specifies deferral of the effect of the change in tax rates over a longer period of time.

Deferred income tax assets and liabilities are also recognized for temporary differences where the deferred income tax benefits or expenses have previously been flowed through in the ratemaking process of the regulated utility. Regulatory tax assets and liabilities are recorded on these deferred tax assets and liabilities to the extent we believe they will be recoverable from or refunded to customers in future rates.

Deferred investment tax credits on utility plant additions, which reduce income taxes payable, are deferred for financial statement purposes and amortized over the life of the related plant.

We recognize interest and penalties related to unrecognized tax benefits, if any, within income tax expense and accrued interest and penalties within the related tax liability line in the consolidated balance sheets. No accrued interest or penalties for uncertain tax benefits have been recorded. See Note 9.

Environmental Contingencies

Loss contingencies are recorded as liabilities when it is probable a liability has been incurred and the amount of the loss is reasonably estimable in accordance with accounting standards for contingencies. Estimating probable losses requires an analysis of uncertainties that often depend upon judgments about potential actions by third parties. Accruals for loss contingencies are recorded based on an analysis of potential results.

With respect to environmental liabilities and related costs, we develop estimates based on a review of information available from numerous sources, including completed studies and site specific negotiations. It is our policy to accrue the full amount of such liability when information is sufficient to reasonably estimate the amount of probable liability. When information is not available to reasonably estimate the probable liability, or when only the range of probable liabilities can be estimated and no amount within the range is more likely than another, it is our policy to accrue at the low end of the range. Accordingly, due to numerous uncertainties surrounding the course of environmental remediation and the preliminary nature of several site investigations, in some cases, we may not be able to reasonably estimate the high end of the range of possible loss. In those cases, we have disclosed the nature of the potential loss and the fact that the high end of the range cannot be reasonably estimated. See Note 15.

Subsequent Events

We monitor significant events occurring after the balance sheet date and prior to the issuance of the financial statements to determine the impacts, if any, of events on the financial statements to be issued. We do not have any subsequent events to report.

3. EARNINGS PER SHARE

Basic earnings or loss per share are computed using net income or loss and the weighted average number of common shares outstanding for each period presented. Diluted earnings per share are computed in the same manner, except it uses the weighted average number of common shares outstanding plus the effects of the assumed exercise of stock options and the payment of estimated stock awards from other stock-based compensation plans that are outstanding at the end of each period presented.

Antidilutive stock awards are excluded from the calculation of diluted earnings or loss per common share. Diluted earnings or loss per share are calculated as follows:

In thousands, except per share data	2017	2016	2015
Net income (loss)	$ (55,623)	$ 58,895	$ 53,703
Average common shares outstanding - basic	28,669	27,647	27,347
Additional shares for stock-based compensation plans (See Note 6)	—	132	70
Average common shares outstanding - diluted	28,669	27,779	27,417
Earnings (loss) per share of common stock - basic	$ (1.94)	$ 2.13	$ 1.96
Earnings (loss) per share of common stock - diluted	$ (1.94)	$ 2.12	$ 1.96
Additional information:			
Antidilutive shares	97	5	12

4. SEGMENT INFORMATION

We primarily operate in two reportable business segments: local gas distribution and gas storage. We also have other investments and business activities not specifically related to one of these two reporting segments, which are aggregated and reported as other. We refer to our local gas distribution business as the utility, and our gas storage segment and other as non-utility. Our utility segment also includes the utility portion of our Mist underground storage facility and our North Mist gas storage expansion in Oregon and NWN Gas Reserves, which is a wholly-owned subsidiary of Energy Corp. Our gas storage segment includes NWN Gas Storage, which is a wholly-owned subsidiary of NWN Energy, Gill Ranch, which is a wholly-owned subsidiary of NWN Gas Storage, the non-utility portion of Mist, and all third-party asset management services. Other includes NNG Financial, non-utility appliance retail center operations, NWN Water, which is pursuing investments in the water sector itself and through its wholly-owned subsidiary FWC Merger Sub, Inc., and NWN Energy's equity investment in TWH, which is pursuing development of a cross-Cascades transmission pipeline project. No individual customer accounts for over 10% of our operating revenues.

Local Gas Distribution

Our local gas distribution segment is a regulated utility principally engaged in the purchase, sale, and delivery of natural gas and related services to customers in Oregon and southwest Washington. As a regulated utility, we are responsible for building and maintaining a safe and reliable pipeline distribution system, purchasing sufficient gas supplies from producers and marketers, contracting for firm and interruptible transportation of gas over interstate pipelines to bring gas from the supply basins into our service territory, and re-selling the gas to customers subject to rates, terms, and conditions approved by the OPUC or WUTC. Gas distribution also includes taking customer-owned gas and transporting it from interstate pipeline connections, or city gates, to the customers' end-use facilities for a fee, which is approved by the OPUC or WUTC. Approximately 89% of our customers are located in Oregon and 11% in Washington. On an annual basis, residential and commercial customers typically account for around 60% of our utility's total volumes delivered and 90% of our utility's margin. Industrial customers largely account for the remaining volumes and utility margin. A small amount of utility margin is also derived from miscellaneous services, gains or losses from an incentive gas cost sharing mechanism, and other service fees.

Industrial sectors we serve include: pulp, paper, and other forest products; the manufacture of electronic, electrochemical and electrometallurgical products; the processing of farm and food products; the production of various mineral products; metal fabrication and casting; the production of machine tools, machinery, and textiles; the manufacture of asphalt, concrete, and rubber; printing and publishing; nurseries; government and educational institutions; and electric generation.

Gas Storage

Our gas storage segment includes natural gas storage services provided to customers primarily from two underground natural gas storage facilities: the Gill Ranch Facility and the non-utility portion of our Mist gas storage facility. In addition to earning revenue from customer storage contracts, we also use an independent energy marketing company to provide asset management services for utility and non-utility capacity, the results of which are included in this business segment.

Mist Gas Storage Facility

Earnings from non-utility assets at our Mist facility in Oregon are primarily related to firm storage capacity revenues. Earnings for the Mist facility also include revenue, net of amounts shared with utility customers, from management of utility assets at Mist and upstream pipeline capacity when not needed to serve utility customers. We retain 80% of the pre-tax income from these services when the costs of the capacity have not been included in utility rates, or 33% of the pre-tax income when the costs have been included in utility rates. The remaining 20% and 67%, respectively, are recorded to a deferred regulatory account for crediting back to utility customers.

Gill Ranch Gas Storage Facility
Gill Ranch has a joint project agreement with Pacific Gas and Electric Company (PG&E) to own and operate the Gill Ranch Facility, an underground natural gas storage facility near Fresno, California. Gill Ranch has a 75% undivided ownership interest in the facility and is also the operator of the facility, which offers storage services to the California market at market-based rates, subject to CPUC regulation including, but not limited to, service terms and conditions and tariff regulations. Although this is a jointly-owned property, each owner is independently responsible for financing its share of the Gill Ranch Facility. As such, the impairment of long-lived assets at the Gill Ranch Facility recognized in 2017 reflects our ownership interest. Revenues are primarily related to firm storage capacity as well as asset management revenues.

Other
We have non-utility investments and other business activities, which are aggregated and reported as other. Other primarily consists of an equity method investment in TWH, which was formed to build and operate an interstate gas transmission pipeline in Oregon (TWP), other pipeline assets in NNG Financial, and non-utility appliance retail center operations. For more information on TWP, see Note 12. Other also includes some corporate operating and non-operating revenues and expenses that cannot be allocated to utility operations. Upon closing agreements to purchase two water utilities, we expect them to be accounted for as other.

NNG Financial's assets primarily consist of an active, wholly-owned subsidiary which owns a 10% interest in an 18-mile interstate natural gas pipeline. NNG Financial's total assets were $0.4 million and $0.5 million at December 31, 2017 and 2016, respectively.

Segment Information Summary
Inter-segment transactions were immaterial for the periods presented. The following table presents summary financial information concerning the reportable segments:

In thousands	Utility	Gas Storage	Other	Total
2017				
Operating revenues	$ 732,942	$ 23,620	$ 5,611	$ 762,173
Depreciation and amortization	79,734	5,844	—	85,578
Income (loss) from operations [1]	132,807	(185,074)	(960)	(53,227)
Net income (loss) [2]	60,509	(116,209)	77	(55,623)
Capital expenditures	211,672	1,923	—	213,595
Total assets at December 31, 2017	2,961,326	59,583	18,837	3,039,746
2016				
Operating revenues	$ 650,477	$ 25,266	$ 224	$ 675,967
Depreciation and amortization	76,289	6,000	—	82,289
Income (loss) from operations	130,570	9,136	(426)	139,280
Net income (loss) [3]	54,567	4,303	25	58,895
Capital expenditures	138,074	1,437	—	139,511
Total assets at December 31, 2016	2,806,627	256,333	16,841	3,079,801
2015				
Operating revenues	$ 702,210	$ 21,356	$ 225	$ 723,791
Depreciation and amortization	74,410	6,513	—	80,923
Income (loss) from operations	119,215	5,032	1	124,248
Net income (loss) [3]	53,391	174	138	53,703
Capital expenditures	115,272	3,048	—	118,320
Total assets at December 31, 2015	2,791,623	261,750	16,037	3,069,410

(1) Includes $192.5 million for an impairment of long-lived assets at the Gill Ranch Facility in Gas Storage.
(2) Includes $21.9 million and $0.6 million of tax benefit in Gas Storage and Other, respectively, and $1.0 million of tax expense in Utility from the enactment of TCJA. Gas Storage also includes an after-tax impairment of long-lived assets at the Gill Ranch Facility of $141.5 million. The TCJA was enacted December 22, 2017 and resulted in the federal tax rate changing from 35% to 21%. The after-tax impairment charge is calculated using our new combined federal and state statutory rate of 26.5%.
(3) Includes $2.0 million in 2016 and $9.1 million in 2015 of after-tax regulatory environmental disallowance charges in Utility.

Utility Margin
Utility margin is a financial measure consisting of utility operating revenues, which are reduced by revenue taxes, the associated cost of gas, and environmental recovery revenues. The cost of gas purchased for utility customers is generally a pass-through cost in the amount of revenues billed to regulated utility customers. Environmental recovery revenues represent collections received from customers through our environmental recovery mechanism in Oregon. These collections are offset by the amortization of environmental liabilities, which is presented as environmental remediation expense in our operating expenses. By subtracting cost of gas and environmental remediation expense from utility operating revenues, utility margin provides a key metric used by our chief operating decision maker in assessing the performance of the utility

segment. The gas storage segment and other emphasize growth in operating revenues as opposed to margin because they do not incur a product cost (i.e. cost of gas sold) like the utility and, therefore, use operating revenues and net income to assess performance.

The following table presents additional segment information concerning utility margin:

In thousands	2017	2016	2015
Utility margin calculation:			
Utility operating revenues	$ 732,942	$ 650,477	$ 702,210
Less: Utility cost of gas	325,019	260,588	327,305
Environmental remediation expense	15,291	13,298	3,513
Utility margin	$ 392,632	$ 376,591	$ 371,392

5. COMMON STOCK

Common Stock

As of December 31, 2017 and 2016, we had 100 million shares of common stock authorized. As of December 31, 2017, we had reserved 43,058 shares for issuance of common stock under the Employee Stock Purchase Plan (ESPP) and 155,086 shares under our Dividend Reinvestment and Direct Stock Purchase Plan (DRPP). At our election, shares sold through our DRPP may be purchased in the open market or through original issuance of shares reserved for issuance under the DRPP.

The Restated Stock Option Plan (SOP) was terminated with respect to new grants in 2012; however, options granted before the Restated SOP was terminated will remain outstanding until the earlier of their expiration, forfeiture, or exercise. There were 91,688 options outstanding at December 31, 2017, which were granted prior to termination of the plan.

During November 2016, we completed an equity issuance consisting of an offering of 880,000 shares of its common stock along with a 30-day option for the underwriters to purchase an additional 132,000 shares. The offering closed on November 16, 2016 and resulted in a total issuance of 1,012,000 shares as both the initial offering and the underwriter option were fully executed. All shares were issued on November 16, 2016 at an offering price of $54.63 per share and resulted in total net proceeds of $52.8 million.

Stock Repurchase Program

We have a share repurchase program under which we may purchase our common shares on the open market or through privately negotiated transactions. We currently have Board authorization through May 2018 to repurchase up to an aggregate of the greater of 2.8 million shares or $100 million. No shares of common stock were repurchased pursuant to this program during the year ended December 31, 2017. Since the plan's inception in 2000, a total of 2.1 million shares have been repurchased at a total cost of $83.3 million.

Summary of Changes in Common Stock

The following table shows the changes in the number of shares of our common stock issued and outstanding:

In thousands	Shares
Balance, December 31, 2014	27,284
Sales to employees under ESPP	19
Stock-based compensation	78
Sales to shareholders under DRPP	46
Balance, December 31, 2015	27,427
Sales to employees under ESPP	18
Stock-based compensation	173
Equity Issuance	1,012
Balance, December 31, 2016	28,630
Sales to employees under ESPP	18
Stock-based compensation	88
Balance, December 31, 2017	28,736

6. STOCK-BASED COMPENSATION

Our stock-based compensation plans are designed to promote stock ownership in NW Natural by employees and officers. These compensation plans include a Long Term Incentive Plan (LTIP), an ESPP, and a Restated SOP.

Long Term Incentive Plan

The LTIP is intended to provide a flexible, competitive compensation program for eligible officers and key employees. Under the LTIP, shares of common stock are authorized for equity incentive grants in the form of stock, restricted stock, restricted stock units, stock options, or performance shares. An aggregate of 1,100,000 shares were authorized for issuance as of December 31, 2017. Shares awarded under the LTIP may be purchased on the open market or issued as original shares.

Of the 1,100,000 shares of common stock authorized for LTIP awards at December 31, 2017, there were 626,960 shares available for issuance under any type of award. This assumes market, performance, and service-based grants currently outstanding are awarded at the target level. There were no outstanding grants of restricted stock or stock options under the LTIP at December 31, 2017 or 2016. The LTIP stock awards are compensatory awards for which compensation expense is based on the fair value of stock awards, with expense being recognized over the performance and vesting period of the outstanding awards. Forfeitures are recognized as they occur.

Performance Shares
Since the LTIP's inception in 2001, performance shares, which incorporate market, performance, and service-based factors, have been granted annually with three-year performance periods. The following table summarizes performance share expense information:

Dollars in thousands	Shares[(1)]	Expense During Award Year[(2)]	Total Expense for Award
Estimated award:			
2015-2017 grant[(3)]	18,300	$ (346)	$ 1,169
Actual award:			
2014-2016 grant	31,388	168	1,685
2013-2015 grant	8,914	312	1,240

(1) In addition to common stock shares, a participant also receives a dividend equivalent cash payment equal to the number of shares of common stock received on the award payout multiplied by the aggregate cash dividends paid per share during the performance period.
(2) Amount represents the expense recognized in the third year of the vesting period noted above. For the 2015-2017 grant, we did not meet targets and reversed expense during 2017 that had been previously recognized.
(3) This represents the estimated number of shares to be awarded as of December 31, 2017 as certain performance share measures had been achieved. Amounts are subject to change with final payout amounts authorized by the Board of Directors in February 2018.

The aggregate number of performance shares granted and outstanding at the target and maximum levels were as follows:

Dollars in thousands	Performance Share Awards Outstanding		2017	Cumulative Expense
Performance Period	Target	Maximum	Expense/ (Reversal)	December 31, 2017
2015-17	29,967	59,934	$ (346)	$ 1,169
2016-18	24,826	49,652	337	815
2017-19	32,680	65,360	942	942
Total	87,473	174,946	$ 933	

For the 2015-2017 and 2016-2018 plan years, performance share awards are based on EPS and Return on Invested Capital (ROIC) factors and a total shareholder return (TSR factor) relative to the Dow Jones U.S. Gas Distribution peer group over the three-year performance period. Additionally, these plans are based on performance results achieved relative to specific core and non-core strategies (strategic factor). For the 2017-2019 plan year, performance share awards are based on the achievement of EPS and ROIC factors, which can be modified by a TSR factor relative to the performance of the Russell 2500 Utilities Index over the three-year performance period and a growth modifier based on accumulative EBITA measure.

Compensation expense is recognized in accordance with accounting standards for stock-based compensation and calculated based on performance levels achieved and an estimated fair value using the Monte-Carlo method. The weighted-average grant date fair value of nonvested shares at December 31, 2017 and 2016 was $56.40 and $50.83 per share, respectively. The weighted-average grant date fair value of shares granted during the year was $57.05 per share and for shares vested during the year was $52.02 per share. As of December 31, 2017, there was $2.8 million of unrecognized compensation expense related to the nonvested portion of performance awards expected to be recognized through 2019.

Restricted Stock Units
In 2012, we began granting RSUs under the LTIP instead of stock options under the Restated SOP. Generally, the RSUs awarded are forfeitable and include a performance-based threshold as well as a vesting period of four years from the grant date. Upon vesting, the RSU holder is issued one share of common stock plus a cash payment equal to the total amount of dividends paid per share between the grant date and vesting date of that portion of the RSU. The fair value of an RSU is equal to the closing market price of the Company's common stock on the grant date. During 2017, total RSU expense was $1.6 million compared to $1.5 million in 2016 and $1.3 million in 2015. As of December 31, 2017, there was $3.1 million of unrecognized compensation cost from grants of RSUs, which is expected to be recognized over a period extending through 2022.

Information regarding the RSU activity is summarized as follows:

	Number of RSUs	Weighted - Average Price Per RSU
Nonvested, December 31, 2014	70,794	$ 44.00
Granted	37,264	46.29
Vested	(19,003)	44.81
Forfeited	(468)	44.99
Nonvested, December 31, 2015	88,587	44.78
Granted	40,271	54.36
Vested	(29,488)	45.56
Forfeited	(9,397)	44.59
Nonvested, December 31, 2016	89,973	48.85
Granted	32,168	60.51
Vested	(35,341)	47.07
Forfeited	(2,278)	53.78
Nonvested, December 31, 2017	84,522	53.90

Restated Stock Option Plan
The Restated SOP was terminated for new option grants in 2012; however, options granted before the plan terminated will remain outstanding until the earlier of their expiration, forfeiture, or exercise. Any new grants of stock options would be made under the LTIP, however, no option grants have been awarded since 2012 and all stock options were vested as of December 31, 2015.

Options under the Restated SOP were granted to officers and key employees designated by a committee of our Board of Directors. All options were granted at an option price equal to the closing market price on the date of grant and may be exercised for a period of up to 10 years and seven days from the date of grant. Option holders may exchange shares they have owned for at least six months, valued at the current market price, to purchase shares at the option price.

Information regarding the Restated SOP activity is summarized as follows:

	Option Shares	Weighted - Average Price Per Share	Intrinsic Value *(In millions)*
Balance outstanding, December 31, 2014	416,088	$ 43.40	$ 2.7
Exercised	(62,900)	39.96	0.5
Forfeited	(500)	45.74	n/a
Balance outstanding, December 31, 2015	352,688	44.00	2.3
Exercised	(172,525)	43.61	2.0
Forfeited	—	n/a	n/a
Balance outstanding, December 31, 2016	180,163	44.38	2.8
Exercised	(88,275)	44.33	1.8
Forfeited	(200)	41.15	n/a
Balance outstanding and exercisable, December 31, 2017	91,688	44.43	1.4

During 2017, cash of $3.9 million was received for stock options exercised and $0.5 million related tax expense was recognized. The weighted-average remaining life of options exercisable and outstanding at December 31, 2017 was 2.47 years.

Employee Stock Purchase Plan

The ESPP allows employees to purchase common stock at 85% of the closing price on the trading day immediately preceding the initial offering date, which is set annually. Each eligible employee may purchase up to $21,199 worth of stock through payroll deductions over a period defined by the Board of Directors, which is currently a 12-month period, with shares issued at the end of the 12-month subscription period.

Stock-Based Compensation Expense

Stock-based compensation expense is recognized as operations and maintenance expense or is capitalized as part of construction overhead. The following table summarizes the financial statement impact of stock-based compensation under our LTIP, Restated SOP and ESPP:

In thousands	2017	2016	2015
Operations and maintenance expense, for stock-based compensation	$ 2,354	$ 2,370	$ 2,673
Income tax benefit	(930)	(924)	(1,012)
Net stock-based compensation effect on net income (loss)	$ 1,424	$ 1,446	$ 1,661
Amounts capitalized for stock-based compensation	$ 528	$ 554	$ 661

7. DEBT

Short-Term Debt

Our primary source of short-term funds is from the sale of commercial paper and bank loans. In addition to issuing commercial paper or bank loans to meet seasonal working capital requirements, short-term debt is used temporarily to fund capital requirements. Commercial paper and bank loans are periodically refinanced through the sale of long-term debt or equity securities. Our commercial paper program is supported by one or more committed credit facilities.

At December 31, 2017 and 2016, total short-term debt outstanding was $54.2 million and $53.3 million, respectively, which was comprised entirely of commercial paper. The weighted average interest rate at December 31, 2017 and 2016 was 1.9% and 0.8%, respectively.

The carrying cost of our commercial paper approximates fair value using Level 2 inputs, due to the short-term nature of the notes. See Note 2 for a description of the fair value hierarchy. At December 31, 2017, our commercial paper had a maximum remaining maturity of 11 days and an average remaining maturity of 6 days.

We have a $300.0 million credit agreement, with a feature that allows us to request increases in the total commitment amount up to a maximum amount of $450.0 million. The maturity of the agreement is December 20, 2019. We have a letter of credit of $100.0 million. Any principal and unpaid interest owed on borrowings under the agreement is due and payable on or before the expiration date. There were no outstanding balances under the agreement and no letters of credit issued or outstanding at December 31, 2017 and 2016.

The credit agreement requires that we maintain credit ratings with Standard & Poor’s (S&P) and Moody’s Investors Service, Inc. (Moody’s) and notify the lenders of any change in our senior unsecured debt ratings or senior secured debt ratings, as applicable, by such rating agencies. A change in our debt ratings is not an event of default, nor is the maintenance of a specific minimum level of debt rating a condition of drawing upon the credit facility. However, interest rates on any loans outstanding under the credit facility are tied to debt ratings, which would increase or decrease the cost of any loans under the credit facility when ratings are changed.

The credit agreement also requires us to maintain a consolidated indebtedness to total capitalization ratio of 70% or less. Failure to comply with this covenant would entitle the lenders to terminate their lending commitments and accelerate the maturity of all amounts outstanding. We were in compliance with this covenant at December 31, 2017 and 2016.

Long-Term Debt

The issuance of FMBs, which includes our medium-term notes, under the Mortgage and Deed of Trust (Mortgage) is limited by eligible property, adjusted net earnings, and other provisions of the Mortgage. The Mortgage constitutes a first mortgage lien on substantially all of our utility property.

Maturities and Outstanding Long-Term Debt

Retirement of long-term debt for each of the 12-month periods through December 31, 2022 and thereafter are as follows:

In thousands	
Year	
2018	$ 97,000
2019	30,000
2020	75,000
2021	60,000
2022	—
Thereafter	524,700

The following table presents our debt outstanding as of December 31:

In thousands	2017	2016
First Mortgage Bonds		
7.000 % Series B due 2017	$ —	$ 40,000
1.545 % Series B due 2018	75,000	75,000
6.600 % Series B due 2018	22,000	22,000
8.310 % Series B due 2019	10,000	10,000
7.630 % Series B due 2019	20,000	20,000
5.370 % Series B due 2020	75,000	75,000
9.050 % Series A due 2021	10,000	10,000
3.176 % Series B due 2021	50,000	50,000
3.542 % Series B due 2023	50,000	50,000
5.620 % Series B due 2023	40,000	40,000
7.720 % Series B due 2025	20,000	20,000
6.520 % Series B due 2025	10,000	10,000
7.050 % Series B due 2026	20,000	20,000
3.211 % Series B due 2026	35,000	35,000
7.000 % Series B due 2027	20,000	20,000
2.822 % Series B due 2027	25,000	—
6.650 % Series B due 2027	19,700	19,700
6.650 % Series B due 2028	10,000	10,000
7.740 % Series B due 2030	20,000	20,000
7.850 % Series B due 2030	10,000	10,000
5.820 % Series B due 2032	30,000	30,000
5.660 % Series B due 2033	40,000	40,000
5.250 % Series B due 2035	10,000	10,000
4.000 % Series B due 2042	50,000	50,000
4.136 % Series B due 2046	40,000	40,000
3.685 % Series B due 2047	75,000	—
	786,700	726,700
Less: Current maturities	97,000	40,000
Total long-term debt	$ 689,700	$ 686,700

First Mortgage Bonds

We issued $100.0 million of FMBs in September 2017 consisting of $25.0 million with a coupon rate of 2.822% and maturity date in 2027 and $75 million with a coupon rate of 3.685% and maturity date in 2047.

Retirements of Long-Term Debt

We redeemed $40.0 million of FMBs with a coupon rate of 7.000% in August 2017.

Fair Value of Long-Term Debt

Our outstanding debt does not trade in active markets. We estimate the fair value of our debt using utility companies with similar credit ratings, terms, and remaining maturities to our debt that actively trade in public markets. These valuations are based on Level 2 inputs as defined in the fair value hierarchy. See Note 2.

The following table provides an estimate of the fair value of our long-term debt, including current maturities of long-term debt, using market prices in effect on the valuation date:

	December 31,	
In thousands	2017	2016
Gross long-term debt	$ 786,700	$ 726,700
Unamortized debt issuance costs	(6,813)	(7,377)
Carrying amount	$ 779,887	$ 719,323
Estimated fair value	$ 853,339	$ 793,339

8. PENSION AND OTHER POSTRETIREMENT BENEFIT COSTS

We maintain a qualified non-contributory defined benefit pension plan, non-qualified supplemental pension plans for eligible executive officers and other key employees, and other postretirement employee benefit plans. We also have a qualified defined contribution plan (Retirement K Savings Plan) for all eligible employees. The qualified defined benefit pension plan and Retirement K Savings Plan have plan assets, which are held in qualified trusts to fund retirement benefits.

Effective January 1, 2007 and 2010, the qualified defined benefit pension plans and postretirement benefits for non-union employees and union employees, respectively, were closed to new participants.

These plans were not available to employees of our non-utility subsidiaries. Non-union and union employees hired or re-hired after December 31, 2006 and 2009, respectively, and employees of NW Natural subsidiaries are provided an enhanced Retirement K Savings Plan benefit.

Effective December 31, 2012, the qualified defined benefit pension plans for non-union and union employees were merged into a single plan.

The following table provides a reconciliation of the changes in benefit obligations and fair value of plan assets, as applicable, for the pension and other postretirement benefit plans, excluding the Retirement K Savings Plan, and a summary of the funded status and amounts recognized in the consolidated balance sheets as of December 31:

	Postretirement Benefit Plans			
	Pension Benefits		Other Benefits	
In thousands	2017	2016	2017	2016
Reconciliation of change in benefit obligation:				
Obligation at January 1	$ 457,839	$ 445,628	$ 29,395	$ 31,049
Service cost	7,090	7,083	341	391
Interest cost	18,111	18,399	1,141	1,175
Net actuarial (gain) loss	34,829	7,688	(213)	(1,488)
Benefits paid[(1)]	(31,580)	(20,959)	(1,737)	(1,732)
Obligation at December 31	$ 486,289	$ 457,839	$ 28,927	$ 29,395
Reconciliation of change in plan assets:				
Fair value of plan assets at January 1	$ 257,714	$ 249,338	$ —	$ —
Actual return on plan assets	40,308	12,593	—	—
Employer contributions	21,483	16,742	1,737	1,732
Benefits paid[(1)]	(31,580)	(20,959)	(1,737)	(1,732)
Fair value of plan assets at December 31	$ 287,925	$ 257,714	$ —	$ —
Funded status at December 31	$ (198,364)	$ (200,125)	$ (28,927)	$ (29,395)

(1) In 2017, we completed a partial buy-out of our qualified defined benefit pension plan in which $9.3 million of plan assets and $8.7 million liabilities were transferred to an insurer to provide annuities for buy-out plan participants.

Our qualified defined benefit pension plan has an aggregate benefit obligation of $449.7 million and $423.5 million at December 31, 2017 and 2016, respectively, and fair values of plan assets of $287.9 million and $257.7 million, respectively. The following table presents amounts realized through regulatory assets or in other comprehensive loss (income) for the years ended December 31:

	Regulatory Assets						Other Comprehensive Loss (Income)		
	Pension Benefits			Other Postretirement Benefits			Pension Benefits		
In thousands	2017	2016	2015	2017	2016	2015	2017	2016	2015
Net actuarial loss (gain)	$ 12,177	$ 14,005	$ 419	$ (214)	$ (1,488)	$ 2,724	$ 2,777	$ (1,196)	$ (2,549)
Settlement Loss	—	—	—	—	—	—	—	193	—
Amortization of:									
Prior service cost	(127)	(230)	(230)	468	468	(197)	—	—	—
Actuarial loss	(14,802)	(13,238)	(16,372)	(696)	(705)	(554)	(946)	1,386	(2,236)
Total	$ (2,752)	$ 537	$ (16,183)	$ (442)	$ (1,725)	$ 1,973	$ 1,831	$ 383	$ (4,785)

The following table presents amounts recognized in regulatory assets and accumulated other comprehensive loss (AOCL) at December 31:

	Regulatory Assets				AOCL	
	Pension Benefits		Other Postretirement Benefits		Pension Benefits	
In thousands	2017	2016	2017	2016	2017	2016
Prior service cost (credit)	$ 49	$ 176	$ (2,206)	$ (2,675)	$ —	$ 1
Net actuarial loss	175,035	177,660	6,964	7,874	13,266	11,434
Total	$ 175,084	$ 177,836	$ 4,758	$ 5,199	$ 13,266	$ 11,435

The following table presents amounts recognized in AOCL and the changes in AOCL related to our non-qualified employee benefit plans:

	Year Ended December 31,	
In thousands	2017	2016
Beginning balance	$ (6,951)	$ (7,162)
Amounts reclassified to AOCL	(2,794)	(1,196)
Amounts reclassified from AOCL:		
Amortization of actuarial losses	946	1,386
Loss from plan settlement	—	193
Total reclassifications before tax	(1,848)	383
Tax expense (benefit)	361	(172)
Total reclassifications for the period	(1,487)	211
Ending balance	$ (8,438)	$ (6,951)

In 2018, an estimated $17.3 million will be amortized from regulatory assets to net periodic benefit costs, consisting of $17.7 million of actuarial losses, and $0.4 million of prior service credits. A total of $0.8 million will be amortized from AOCL to earnings related to actuarial losses in 2018.

Our assumed discount rate for the pension plan and other postretirement benefit plans was determined independently based on the Citigroup Above Median Curve (discount rate curve), which uses high quality corporate bonds rated AA- or higher by S&P or Aa3 or higher by Moody's. The discount rate curve was applied to match the estimated cash flows in each of our plans to reflect the timing and amount of expected future benefit payments for these plans.

Our assumed expected long-term rate of return on plan assets for the qualified pension plan was developed using a weighted-average of the expected returns for the target asset portfolio. In developing the expected long-term rate of return assumption, consideration was given to the historical performance of each asset class in which the plan's assets are invested and the target asset allocation for plan assets.

Our investment strategy and policies for qualified pension plan assets held in the retirement trust fund were approved by our Retirement Committee, which is composed of senior management with the assistance of an outside investment consultant. The policies set forth the guidelines and objectives governing the investment of plan assets. Plan assets are invested for total return with appropriate consideration for liquidity, portfolio risk, and return expectations. All investments are expected to satisfy the prudent investments rule under the Employee Retirement Income Security Act of 1974. The approved asset classes may include cash and short-term investments, fixed income, common stock and convertible securities, absolute and real return strategies, real estate, and investments in NW Natural securities. Plan assets may be invested in separately managed accounts or in commingled or mutual funds. Investment re-balancing takes place periodically as needed, or when significant cash flows occur, in order to maintain the allocation of assets within the stated target ranges. The retirement trust fund is not currently invested in NW Natural securities.

The following table presents the pension plan asset target allocation at December 31, 2017:

Asset Category	Target Allocation
U.S. large cap equity	29.3%
U.S. small/mid cap equity	6.9
Non-U.S. equity	28.0
Emerging markets equity	11.8
Long government/credit	17.5
High yield bonds	2.0
Emerging market debt	3.5
Real estate funds	1.0

Our non-qualified supplemental defined benefit plan obligations were $36.6 million and $34.3 million at December 31, 2017 and 2016, respectively. These plans are not subject to regulatory deferral, and the changes in actuarial gains and losses, prior service costs, and transition assets or obligations are recognized in AOCL, net of tax until they are amortized as a component of net periodic benefit cost. These are unfunded, non-qualified plans with no plan assets; however, we indirectly fund a significant portion of our obligations with company and trust-owned life insurance and other assets.

Our other postretirement benefit plans are unfunded plans but are subject to regulatory deferral. The actuarial gains and losses, prior service costs, and transition assets or obligations for these plans are recognized as a regulatory asset.

Net periodic benefit costs consist of service costs, interest costs, the amortization of actuarial gains and losses, and the expected returns on plan assets, which are based in part on a market-related valuation of assets. The market-related valuation reflects differences between expected returns and actual investment returns with the differences recognized over a three-year or less period from the year in which they occur, thereby reducing year-to-year net periodic benefit cost volatility.

The following table provides the components of net periodic benefit cost for our pension and other postretirement benefit plans for the years ended December 31:

	Pension Benefits			Other Postretirement Benefits		
In thousands	2017	2016	2015	2017	2016	2015
Service cost	$ 7,090	$ 7,083	$ 8,267	$ 341	$ 391	$ 527
Interest cost	18,111	18,399	18,360	1,141	1,175	1,179
Expected return on plan assets	(20,433)	(20,054)	(20,676)	—	—	—
Amortization of prior service costs	127	231	231	(468)	(468)	197
Amortization of net actuarial loss	15,748	14,624	18,609	696	705	554
Settlement expense	—	193	—	—	—	—
Net periodic benefit cost	20,643	20,476	24,791	1,710	1,803	2,457
Amount allocated to construction	(6,597)	(5,746)	(6,834)	(587)	(600)	(808)
Amount deferred to regulatory balancing account[1]	(6,542)	(6,252)	(8,241)	—	—	—
Net amount charged to expense	$ 7,504	$ 8,478	$ 9,716	$ 1,123	$ 1,203	$ 1,649

(1) The deferral of defined benefit pension plan expenses above or below the amount set in rates was approved by the OPUC, with recovery of these deferred amounts through the implementation of a balancing account. The balancing account includes the expectation of higher net periodic benefit costs than costs recovered in rates in the near-term with lower net periodic benefit costs than costs recovered in rates expected in future years. Deferred pension expense balances include accrued interest at the utility's authorized rate of return, with the equity portion of the interest recognized when amounts are collected in rates.

Net periodic benefit costs are reduced by amounts capitalized to utility plant based on approximately 25% to 35% payroll overhead charge. In addition, a certain amount of net periodic benefit costs are recorded to the regulatory balancing account for pensions.

Net periodic pension cost less amounts charged to capital accounts and regulatory balancing accounts are expenses recognized in earnings.

The following table provides the assumptions used in measuring periodic benefit costs and benefit obligations for the years ended December 31:

	Pension Benefits			Other Postretirement Benefits		
	2017	2016	2015	2017	2016	2015
Assumptions for net periodic benefit cost:						
Weighted-average discount rate	3.99%	4.17%	3.82%	3.85%	4.00%	3.74%
Rate of increase in compensation	3.25-4.5%	3.25-4.5%	3.25-5.0%	n/a	n/a	n/a
Expected long-term rate of return	7.50%	7.50%	7.50%	n/a	n/a	n/a
Assumptions for year-end funded status:						
Weighted-average discount rate	3.52%	4.00%	4.21%	3.44%	3.85%	4.00%
Rate of increase in compensation	3.25-4.5%	3.25-4.5%	3.25-4.5%	n/a	n/a	n/a
Expected long-term rate of return	7.50%	7.50%	7.50%	n/a	n/a	n/a

The assumed annual increase in health care cost trend rates used in measuring other postretirement benefits as of December 31, 2017 was 7.50%. These trend rates apply to both medical and prescription drugs. Medical costs and prescription drugs are assumed to decrease gradually each year to a rate of 4.75% by 2026.

Assumed health care cost trend rates can have a significant effect on the amounts reported for the health care plans; however, other postretirement benefit plans have a cap on the amount of costs reimbursable by us.

A one percentage point change in assumed health care cost trend rates would have the following effects:

In thousands	1% Increase	1% Decrease
Effect on net periodic postretirement health care benefit cost	$ 44	$ (39)
Effect on the accumulated postretirement benefit obligation	478	(428)

We review mortality assumptions annually and will update for material changes as necessary. In 2017, our mortality rate assumptions were updated from RP-2006 mortality tables for employees and healthy annuitants with a fully generational projection using scale MP-2016 to corresponding RP-2006 mortality tables using scale MP-2017, which partially offset increases of our projected benefit obligation.

The following table provides information regarding employer contributions and benefit payments for the qualified pension plan, non-qualified pension plans, and other postretirement benefit plans for the years ended December 31, and estimated future contributions and payments:

In thousands	Pension Benefits	Other Benefits
Employer Contributions:		
2016	$ 16,742	$ 1,732
2017	21,483	1,737
2018 (estimated)	17,710	1,835
Benefit Payments:		
2015	35,923	2,018
2016	20,959	1,732
2017	31,580	1,737
Estimated Future Benefit Payments:		
2018	22,679	1,835
2019	23,546	1,871
2020	24,542	1,861
2021	25,471	1,904
2022	26,095	1,886
2023-2027	145,065	9,261

Employer Contributions to Company-Sponsored Defined Benefit Pension Plans

We make contributions to our qualified defined benefit pension plans based on actuarial assumptions and estimates, tax regulations, and funding requirements under federal law. The Pension Protection Act of 2006 (the Act) established funding requirements for defined benefit plans. The Act establishes a 100% funding target over seven years for plan years beginning after December 31, 2008. In 2012 the Moving Ahead for Progress in the 21st Century Act (MAP-21) legislation changed several provisions affecting pension plans, including temporary funding relief and Pension Benefit Guaranty Corporation (PBGC) premium increases, which reduces the level of minimum required contributions in the near-term but generally increases contributions in the long-run and increases the operational costs of running a pension plan. In 2014, the Highway and Transportation Funding Act (HATFA) was signed and extends certain aspects of MAP-21 as well as modifies the phase-out periods for the limitations.

Our qualified defined benefit pension plan is currently underfunded by $161.7 million at December 31, 2017. Including the impacts of MAP-21 and HATFA, we made cash contributions totaling $19.4 million to our qualified defined benefit pension plan for 2017. During 2018, we expect to make contributions of approximately $15.5 million to this plan.

Multiemployer Pension Plan

In addition to the Company-sponsored defined benefit plans presented above, prior to 2014 we contributed to a multiemployer pension plan for our utility's union employees known as the Western States Office and Professional Employees International Union Pension Fund (Western States Plan). The plan's employer identification number is 94-6076144. Effective December 22, 2013, we withdrew from the plan, which was a noncash transaction. Vested participants will receive all benefits accrued through the date of withdrawal. As the plan was underfunded at the time of withdrawal, we were assessed a withdrawal liability of $8.3 million, plus interest, which requires NW Natural to pay $0.6 million each year to the plan for 20 years beginning in July 2014. The cost of the withdrawal liability was deferred to a regulatory account on the balance sheet.

We made payments of $0.6 million for 2017, and as of December 31, 2017 the liability balance was $7.1 million. For 2016 and 2015, contributions to the plan were $0.6 million and $0.6 million, respectively, which was approximately 4% to 5% of the total contributions to the plan by all employer participants in those years.

Defined Contribution Plan

The Retirement K Savings Plan is a qualified defined contribution plan under Internal Revenue Code Sections 401(a) and 401(k). Employer contributions totaled $5.4 million, $4.6 million, and $3.7 million for 2017, 2016, and 2015, respectively. The Retirement K Savings Plan includes an Employee Stock Ownership Plan.

Deferred Compensation Plans

The supplemental deferred compensation plans for eligible officers and senior managers are non-qualified plans. These plans are designed to enhance the retirement savings of employees and to assist them in strengthening their financial security by providing an incentive to save and invest regularly.

Fair Value

Below is a description of the valuation methodologies used for assets measured at fair value. In cases where the pension plan is invested through a collective trust fund or mutual fund, the fund's market value is utilized. Market values for investments directly owned are also utilized.

U.S. LARGE CAP EQUITY and U.S. SMALL/MID CAP EQUITY. These are Level 1 and non-published net asset value (NAV) assets. The Level 1 assets consist of directly held stocks and mutual funds with a readily determinable fair value, including a published NAV. The non-published NAV assets consist of commingled trusts where NAV is not published but the investment can be readily disposed of at NAV or market value. Directly held stocks are valued at the closing price reported in the active market on which the individual security is traded. Mutual funds and commingled trusts are valued at NAV and the unit price, respectively. This asset class includes investments primarily in U.S. common stocks.

NON-U.S. EQUITY. These are Level 1 and non-published NAV assets. The Level 1 assets consist of directly held stocks, and the non-published NAV assets consist of commingled trusts where the NAV/unit price is not published but the investment can be readily disposed of at the NAV/unit price. Directly held stocks are valued at the closing price reported in the active market on which the individual security is traded, and the commingled trusts are valued at unit price. This asset class includes investments primarily in foreign equity common stocks.

EMERGING MARKETS EQUITY. These are non-published NAV assets consisting of an open-end mutual fund where the NAV price is not published but the investment can be readily disposed of at the NAV, and a commingled trust where the investment can be readily disposed of at unit price. This asset class includes investments primarily in common stocks in emerging markets.

FIXED INCOME. These are non-published NAV assets consisting of a commingled trust, valued at unit price, where unit price is not published, but the investment can be readily disposed of at the unit price. This asset class includes investments primarily in investment grade debt and fixed income securities.

LONG GOVERNMENT/CREDIT. These are non-published NAV and Level 2 assets. The non-published NAV assets include commingled trusts, valued at unit price, where unit price is not published, but the investment can be readily disposed of at the unit price. The Level 2 assets consist of directly held fixed-income securities, with readily determinable fair values, whose values are determined by closing prices if available and by matrix prices for illiquid securities. This asset class includes long duration fixed income investments primarily in U.S. treasuries, U.S. government agencies, municipal securities, mortgage-backed securities, asset-backed securities, as well as U.S. and international investment-grade corporate bonds.

HIGH YIELD BONDS. These are non-published NAV assets, consisting of a limited partnership and a commingled trust where the valuation is not published but the investment can be readily disposed of at market value, valued at NAV or unit price, respectively. This asset class includes investments primarily in high yield bonds.

EMERGING MARKET DEBT. This is a non-published NAV asset consisting of a commingled trust with a readily determinable fair value, where unit price is not published, but the investment can be readily disposed of at the unit price. This asset class includes investments primarily in emerging market debt.

REAL ESTATE. These are Level 1 and non-published NAV assets. The Level 1 asset is a mutual fund with a readily determinable fair value, including a published NAV. The non-published NAV asset is a commingled trust with a readily determinable fair value, where unit price is not published, but the investment can be readily disposed of at the unit price. This asset class includes investments primarily in real estate investment trust (REIT) equity securities globally.

ABSOLUTE RETURN STRATEGY. This is a non-published NAV asset consisting of a hedge fund of funds where the valuation is not published. This hedge fund of funds is winding down. Based on recent dispositions, we believe the remaining investment is fairly valued. The hedge fund of funds is valued at the weighted average value of investments in various hedge funds, which in turn are valued at the closing price of the underlying securities. This asset class primarily includes investments in common stocks and fixed income securities.

CASH AND CASH EQUIVALENTS. These are Level 1 and non-published NAV assets. The Level 1 assets consist of cash in U.S. dollars, which can be readily disposed of at face value. The non-published NAV assets represent mutual funds without published NAV's but the investment can be readily disposed of at the NAV. The mutual funds are valued at the NAV of the shares held by the plan at the valuation date.

The preceding valuation methods may produce a fair value calculation that is not indicative of net realizable value or reflective of future fair values. Although we believe these valuation methods are appropriate and consistent with other market participants, the use of different methodologies or assumptions to determine the fair value of certain investments could result in a different fair value measurement at the reporting date.

Investment securities are exposed to various financial risks including interest rate, market, and credit risks. Due to the level of risk associated with certain investment securities, it is reasonably possible that changes in the values of our investment securities will occur in the near term and such changes could materially affect our investment account balances and the amounts reported as plan assets available for benefit payments.

The following table presents the fair value of plan assets, including outstanding receivables and liabilities, of the retirement trust fund:

In thousands	December 31, 2017				
Investments	Level 1	Level 2	Level 3	Non-Published NAV[1]	Total
U.S. large cap equity	$ —	$ —	$ —	$ 102,851	$ 102,851
U.S. small/mid cap equity	—	—	—	16,423	16,423
Non-U.S. equity	21,211	—	—	56,075	77,286
Emerging markets equity	—	—	—	28,743	28,743
Fixed income	—	—	—	2,781	2,781
Long government/credit	—	—	—	33,081	33,081
High yield bonds	—	—	—	2,777	2,777
Emerging market debt	—	—	—	12,605	12,605
Real estate	—	—	—	5,544	5,544
Absolute return strategy	—	—	—	189	189
Cash and cash equivalents	82	—	—	5,533	5,615
Total investments	$ 21,293	$ —	$ —	$ 266,602	$ 287,895

	December 31, 2016				
Investments	Level 1	Level 2	Level 3	Non-Published NAV[1]	Total
U.S. large cap equity	$ 49,841	$ —	$ —	$ 5,655	$ 55,496
U.S. small/mid cap equity	18,629	—	—	10,232	28,861
Non-U.S. equity	22,404	—	—	25,346	47,750
Emerging markets equity	—	—	—	13,457	13,457
Fixed income	—	—	—	6,719	6,719
Long government/credit	—	34,955	—	17,960	52,915
High yield bonds	—	—	—	14,072	14,072
Emerging market debt	—	—	—	8,504	8,504
Real estate	17,857	—	—	882	18,739
Absolute return strategy	—	—	—	3,111	3,111
Cash and cash equivalents	$ 9	$ —	$ —	$ 2,482	$ 2,491
Total investments	$ 108,740	$ 34,955	$ —	$ 108,420	$ 252,115

	December 31,	
	2017	2016
Receivables:		
Accrued interest and dividend income	$ 30	$ 451
Due from broker for securities sold	—	5,170
Total receivables	$ 30	$ 5,621
Liabilities:		
Due to broker for securities purchased	$ —	$ 22
Total investment in retirement trust	$ 287,925	$ 257,714

(1) The fair value for these investments is determined using Net Asset Value per share (NAV) as of December 31, as a practical expedient, and therefore they are not classified within the fair value hierarchy. These investments primarily consist of institutional investment products, for which the NAV is generally not publicly available.

9. INCOME TAX

The following table provides a reconciliation between income taxes calculated at the statutory federal tax rate and the provision for income taxes reflected in the consolidated statements of comprehensive income or loss for December 31:

Dollars in thousands	2017	2016	2015
Income taxes (benefits) at federal statutory rate	$(30,233)	$ 34,863	$ 31,310
Increase (decrease):			
State income tax, net of federal	(5,784)	4,582	4,195
Amortization of investment tax credits	(4)	(41)	(118)
Differences required to be flowed-through by regulatory commissions	2,357	2,357	2,357
Gains on company and trust-owned life insurance	(872)	(594)	(766)
Effect of TCJA	(21,429)	—	—
Deferred Tax Rate Differential Post-TCJA	26,947	—	—
Other, net	(1,739)	(453)	(1,225)
Total provision for income taxes (benefits)	$(30,757)	$ 40,714	$ 35,753
Effective tax rate	35.6%	40.9%	40.0%

The effective income tax rate for 2017 compared to 2016 changed primarily as a result of the TCJA, the equity portion of AFUDC and excess tax benefits related to stock-based compensation. The effective income tax rate increase from 2016 compared to 2015 was primarily the result of lower depletion deductions from gas reserves activity in 2016.

The provision for current and deferred income taxes consists of the following at December 31:

In thousands	2017	2016	2015
Current			
Federal	$ 16,403	$ 7,402	$ 10,558
State	4,892	2,042	61
	21,295	9,444	10,619
Deferred			
Federal	(41,134)	26,219	18,729
State	(10,918)	5,051	6,405
	(52,052)	31,270	25,134
Total provision for income taxes (loss benefits)	$ (30,757)	$ 40,714	$ 35,753

At December 31, 2017 and 2016, regulatory income tax assets of $21.3 million and $43.0 million, respectively, were recorded, a portion of which is recorded in current assets. These regulatory income tax assets primarily represent future rate recovery of deferred tax liabilities, resulting from differences in utility plant financial statement and tax bases and utility plant removal costs, which were previously flowed through for rate making purposes and to take into account the additional future taxes, which will be generated by that recovery. These deferred tax liabilities, and the associated regulatory income tax assets, are currently being recovered through customer rates. At December 31, 2017, we had a regulatory income tax asset of $0.9 million representing probable future rate recovery of deferred tax liabilities resulting from the equity portion of AFUDC.

The following table summarizes the total provision (benefit) for income taxes for the utility and non-utility business segments for December 31:

In thousands	2017	2016	2015
Utility:			
Current	$ 21,453	$ 10,300	$ 15,890
Deferred	19,479	28,749	20,834
Deferred investment tax credits	(4)	(41)	(118)
	40,928	39,008	36,606
Non-utility business segments:			
Current	(158)	(856)	(5,271)
Deferred	(71,527)	2,562	4,418
	(71,685)	1,706	(853)
Total provision for income taxes	$(30,757)	$ 40,714	$ 35,753

The following table summarizes the tax effect of significant items comprising our deferred income tax accounts at December 31:

In thousands	2017	2016
Deferred tax liabilities:		
Plant and property	$ 296,114	$ 428,642
Regulatory income tax assets	22,209	43,048
Regulatory liabilities	29,114	48,291
Non-regulated deferred tax liabilities	933	51,446
Total	$ 348,370	$ 571,427
Deferred tax assets:		
Regulatory income tax liabilities	$ 56,470	$ —
Non-regulated deferred tax assets	17,796	—
Pension and postretirement obligations	3,512	4,493
Alternative minimum tax credit carryforward	66	9,853
Total	$ 77,844	$ 14,346
Deferred income tax liabilities, net	$ 270,526	$ 557,081
Deferred investment tax credits	—	4
Deferred income taxes and investment tax credits	$ 270,526	$ 557,085

Management assesses the available positive and negative evidence to estimate if sufficient taxable income will be generated to utilize the existing deferred tax assets. Based upon this assessment, we have determined we are more likely than not to realize all deferred tax assets recorded as of December 31, 2017.

As a result of certain realization requirements prescribed in the accounting guidance for income taxes, the tax benefit of statutory depletion is recognized no earlier than the year in which the depletion is deductible on our federal income tax return. Income tax expense decreased by $0.9 million in 2015 as a result of realizing deferred depletion benefit from 2013 and 2014. This benefit is included in Other, net in the statutory rate reconciliation table.

Uncertain tax positions are accounted for in accordance with accounting standards that require management's assessment of the anticipated settlement outcome of material uncertain tax positions taken in a prior year, or planned to be taken in the current year. Until such positions are sustained, we would not recognize the uncertain tax benefits resulting from such positions. No reserves for uncertain tax positions were recorded as of December 31, 2017, 2016, or 2015.

Our federal income tax returns for tax years 2013 and earlier are closed by statute. The IRS Compliance Assurance Process (CAP) examination of the 2013, 2014, and 2015 tax years have been completed. There were no material changes to these returns as filed. The 2016 and 2017 tax years are currently under IRS CAP examination. Our 2018 CAP application has been accepted by the IRS. Under the CAP program, we work with the IRS to identify and resolve material tax matters before the tax return is filed each year. As of December 31, 2017, income tax years 2014 through 2016 remain open for state examination.

U.S. Federal TCJA Matters

On December 22, 2017, the TCJA was enacted and permanently lowers the U.S. federal corporate income tax rate to 21% from the existing maximum rate of 35%, effective for our tax year beginning January 1, 2018. The TCJA includes specific provisions related to regulated public utilities that provide for the continued deductibility of interest expense and the elimination of bonus depreciation for property acquired after September 27, 2017.

As a result of the reduction of the U.S. corporate income tax rate to 21%, U.S. GAAP requires deferred tax assets and liabilities be revalued as of the date of enactment, with resulting tax effects accounted for in the reporting period of enactment. We recorded a net revaluation of deferred tax asset and liability balances of $196.4 million as of December 31, 2017. This revaluation had no impact on our 2017 cash flows.

The net change in our utility deferred taxes, that were determined to have previously been included in ratemaking activities by the OPUC and WUTC, was recorded as a net regulatory liability that is expected to accrue to the future benefit of customers. It is possible that this estimated regulatory liability balance of $213.3 million, which includes a gross up for income taxes of $56.5 million, may increase or decrease as a result of future regulatory guidance by the OPUC and WUTC or as additional authoritative interpretation of the TCJA becomes available.

The change in our utility deferred taxes of $18.2 million, associated with tax benefits that have previously been flowed through to customers or for the equity portion of AFUDC, resulted in an identical reduction in the associated regulatory assets. This change had no impact on our income tax expense. The net change in our utility deferred taxes, that were determined to have been previously excluded from ratemaking activities by the OPUC and WUTC, and the change in deferred taxes associated with the gas storage segment and other non-regulated operations, was recorded as a net reduction of income tax expense of $21.4 million.

Under pre-TCJA law, business interest is generally deductible in the determination of taxable income. The TCJA imposes a new limitation on the deductibility of net business interest expense in excess of approximately 30% of adjusted taxable income. Taxpayers operating in the trade or business of public regulated utilities are excluded from these new interest expense limitations.

There is uncertainty whether the new interest expense limitation may apply to our non-regulated operations. The legislative history indicates that all members of a consolidated or affiliated group are treated as a single taxpayer with respect to applying business interest limitations. Future authoritative guidance may indicate that net interest expense must be allocated between regulated and non-regulated activities within the consolidated group. Until such time that additional guidance is available that eliminates this uncertainty, we are unable to estimate whether the new interest limitation rules will impact our future operating results. The new interest limitation rules are effective for taxable years beginning after December 31, 2017. There is no grandfathering for debt instruments outstanding prior to such date. Net business interest expense amounts disallowed may be carried forward indefinitely and treated as interest in succeeding taxable years.

The TCJA generally provides for immediate full expensing for qualified property acquired and placed in service after September 27, 2017 and before January 1, 2023. This would generally provide for accelerated cost recovery for capital investments. However, the definition of qualified property excludes property used in the trade or business of a public regulated utility. The definition of utility trade or business is the same as that used by the TCJA with respect to the imposition of the net interest expense limitation discussed above. As a result, a similar uncertainty exists with respect to whether the exclusion from full expensing will apply to our full consolidated group, which primarily operates as a regulated public utility, or whether full expensing will be available to our non-regulated activities.

An additional uncertainty exists with respect to whether 50% bonus depreciation, which was in effect prior to the TCJA, will apply to property for which a contract was entered into or significant construction had occurred prior to September 27, 2017, but that was not placed in service until after that date. We excluded all assets placed in service by the consolidated group after September 27, 2017 from bonus depreciation. If future authoritative guidance indicates that bonus depreciation is available to us for these capital expenditures, this would primarily result in a decrease to our current income taxes payable and an increase in regulatory liability.

The SEC staff issued Staff Accounting Bulletin 118, which provides guidance on accounting for the tax effects of the TCJA. SAB 118 provides a measurement period that should not extend beyond one year from the TCJA enactment date for companies to complete the accounting under ASC 740. To the extent that a company's accounting for certain income tax effects of the TCJA is incomplete but it is able to determine a reasonable estimate, it must record a provisional estimate in the financial statements. Consistent with SAB 118, the determination to exclude all assets placed in service after September 27, 2017 from bonus depreciation is provisional.

We primarily operate in the States of Oregon and Washington. The extent to which a particular state adopts the U.S. Internal Revenue Code directly affects the application of the enacted federal changes of the TCJA to its taxable income computation. To varying degrees, Oregon and Washington corporate business tax approaches rely on federal income tax law, including the Internal Revenue Code and the associated Treasury regulations. It is possible that the federal changes resulting from the TCJA will cause states to reassess their future conformity, however, we have evaluated the state impacts of the TCJA under current law.

Oregon automatically adopts changes to the U.S. Internal Revenue Code related to the calculation of consolidated corporate taxable income. By both State statute and administrative rule, Oregon corporation excise tax law, as related to the definition of taxable income, is tied to federal tax law as applicable to our tax year. Changes enacted to the definition of federal taxable income by the TCJA are effective for Oregon tax purposes in the same manner as for federal tax purposes. As a result, the net interest limitation and full expensing exclusions, discussed above, apply to Oregon as well.

Washington State does not have a corporate income tax, but rather imposes a tax on our gross receipts. The TCJA does not include a change to the definition of gross receipts, or the timing of their recognition, that is currently anticipated to impact us. As a result, no change to Washington State reporting is anticipated.

10. PROPERTY, PLANT, AND EQUIPMENT

The following table sets forth the major classifications of our property, plant, and equipment and accumulated depreciation at December 31:

In thousands	2017	2016
Utility plant in service	$2,975,217	$2,843,243
Utility construction work in progress	159,924	62,264
Less: Accumulated depreciation	942,879	903,096
Utility plant, net	2,192,262	2,002,411
Non-utility plant in service	75,639	299,378
Non-utility construction work in progress	4,671	3,931
Less: Accumulated depreciation	17,598	44,820
Non-utility plant, net	62,712	258,489
Total property, plant, and equipment	$2,254,974	$2,260,900
Capital expenditures in accrued liabilities	$ 34,976	$ 9,547

The weighted average depreciation rate for utility assets was 2.8% for utility assets during 2017, 2016, and 2015. The weighted average depreciation rate for non-utility assets was 1.9% in 2017, 2.0% in 2016, and 2.2% in 2015.

Accumulated depreciation does not include the accumulated provision for asset removal costs of $360.9 million and $341.1 million at December 31, 2017 and 2016, respectively. These accrued asset removal costs are reflected on the balance sheet as regulatory liabilities. See Note 2. During 2017 and 2016, we did not acquire any equipment under capital leases.

11. GAS RESERVES

We have invested $188 million through our gas reserves program in the Jonah Field located in Wyoming as of December 31, 2017. Gas reserves are stated at cost, net of regulatory amortization, with the associated deferred tax benefits recorded as liabilities on the consolidated balance sheets. Our investment in gas reserves provides long-term price protection for utility customers through the original agreement with Encana Oil & Gas (USA) Inc. under which we invested $178 million and the amended agreement with Jonah Energy LLC under which an additional $10 million was invested.

We entered into our original agreements with Encana in 2011 under which we hold working interests in certain sections of the Jonah Field. Gas produced in these sections is sold at prevailing market prices, and revenues from such sales, net of associated operating and production costs and amortization, are credited to the utility's cost of gas. The cost of gas, including a carrying cost for the rate base investment, is included in our annual Oregon PGA filing, which allows us to recover these costs through customer rates. Our investment under the original agreement, less accumulated amortization and deferred taxes, earns a rate of return.

In March 2014, we amended the original gas reserves agreement in order to facilitate Encana's proposed sale of its interest in the Jonah field to Jonah Energy. Under the amendment, we ended the drilling program with Encana, but increased our working interests in our assigned sections of the Jonah field. We also retained the right to invest in new wells with Jonah Energy. Under the amended agreement we still have the option to invest in additional wells on a well-by-well basis with drilling costs and resulting gas volumes shared at our amended proportionate working interest for each well in which we invest. We elected to participate in some of the additional wells drilled in 2014, but have not had the opportunity to participate in additional wells since 2014. However, we may have the opportunity to participate in more wells in the future.

Gas produced from the additional wells is included in our Oregon PGA at a fixed rate of $0.4725 per therm, which approximates the 10-year hedge rate plus financing costs at the inception of the investment.

Gas reserves acted to hedge the cost of gas for approximately 6%, 8% and 11% of our utility's gas supplies for the years ended December 31, 2017, 2016, and 2015 respectively.

The following table outlines our net gas reserves investment at December 31:

In thousands	2017	2016
Gas reserves, current	$ 15,704	$ 15,926
Gas reserves, non-current	171,832	171,610
Less: Accumulated amortization	87,779	71,426
Total gas reserves[1]	99,757	116,110
Less: Deferred taxes on gas reserves	22,712	28,119
Net investment in gas reserves	$ 77,045	$ 87,991

(1) Our net investment in additional wells included in total gas reserves was $5.8 million and $6.7 million at December 31, 2017 and 2016, respectively.

Our investment is included in our consolidated balance sheets under gas reserves with our maximum loss exposure limited to our investment balance.

12. INVESTMENTS

Investments include financial investments in life insurance policies, and equity method investments in certain partnerships and limited liability companies. The following table summarizes our other investments at December 31:

In thousands	2017	2016
Investments in life insurance policies	$ 50,792	$ 52,719
Investments in gas pipeline	13,669	13,767
Other	1,902	1,890
Total other investments	$ 66,363	$ 68,376

Investment in Life Insurance Policies

We have invested in key person life insurance contracts to provide an indirect funding vehicle for certain long-term employee and director benefit plan liabilities. The amount in the above table is reported at cash surrender value, net of policy loans.

Investments in Gas Pipeline

TWP, a wholly-owned subsidiary of TWH, is pursuing the development of a new gas transmission pipeline that would provide an interconnection with our utility distribution system. NWN Energy, a wholly-owned subsidiary of NW Natural, owns 50% of TWH, and 50% is owned by TransCanada American Investments Ltd., an indirect wholly-owned subsidiary of TransCanada Corporation.

Variable Interest Entity (VIE) Analysis

TWH is a VIE, with our investment in TWP reported under equity method accounting. We have determined we are not the primary beneficiary of TWH's activities as we only have a 50% share of the entity, and there are no stipulations that allow us a disproportionate influence over it. Our investments in TWH and TWP are included in other investments on our balance sheet. If we do not develop this investment, then our maximum loss exposure related to TWH is limited to our equity investment balance, less our share of any cash or other assets available to us as a 50% owner. Our investment balance in TWH was $13.4 million at December 31, 2017 and 2016.

Impairment Analysis

Our investments in nonconsolidated entities accounted for under the equity method are reviewed for impairment at each reporting period and following updates to our corporate planning assumptions. If it is determined a loss in value is other than temporary, a charge is recognized for the difference between the investment's carrying value and its estimated fair value. Fair value is based on quoted market prices when available or on the present value of expected future cash flows. Differing assumptions could affect the timing and amount of a charge recorded in any period.

In 2011, TWP withdrew its original application with the FERC for a proposed natural gas pipeline in Oregon and informed FERC that it intended to re-file an application to reflect changes in the project scope aligning the project with the region's current and future gas infrastructure needs. TWP continues working with customers in the Pacific Northwest to further understand their gas transportation needs and determine the commercial support for a revised pipeline proposal. A new FERC certificate application is expected to be filed to reflect a revised scope based on these regional needs.

Our equity investment was not impaired at December 31, 2017 as the fair value of expected cash flows from planned development exceeded our remaining equity investment of $13.4 million at December 31, 2017. However, if we learn that the project is not viable or will not go forward, we could be required to recognize a maximum charge of up to approximately $13.4 million based on the current amount of our equity investment, net of cash and working capital at TWP. We will continue to monitor and update our impairment analysis as required.

13. DERIVATIVE INSTRUMENTS

We enter into financial derivative contracts to hedge a portion of our utility's natural gas sales requirements. These contracts include swaps, options, and combinations of option contracts. We primarily use these derivative financial instruments to manage commodity price variability. A small portion of our derivative hedging strategy involves foreign currency exchange contracts.

We enter into these financial derivatives, up to prescribed limits, primarily to hedge price variability related to our physical gas supply contracts as well as to hedge spot purchases of natural gas. The foreign currency forward contracts are used to hedge the fluctuation in foreign currency exchange rates for pipeline demand charges paid in Canadian dollars.

In the normal course of business, we also enter into indexed-price physical forward natural gas commodity purchase contracts and options to meet the requirements of utility customers. These contracts qualify for regulatory deferral accounting treatment.

We also enter into exchange contracts related to the third-party asset management of our gas portfolio, some of which are derivatives that do not qualify for hedge accounting or regulatory deferral, but are subject to our regulatory sharing agreement. These derivatives are recognized in operating revenues in our gas storage segment, net of amounts shared with utility customers.

Notional Amounts

The following table presents the absolute notional amounts related to open positions on our derivative instruments:

	At December 31,	
In thousands	2017	2016
Natural gas (in therms):		
Financial	429,100	477,430
Physical	520,268	535,450
Foreign exchange	$ 7,669	$ 7,497

Purchased Gas Adjustment (PGA)

Derivatives entered into by the utility for the procurement or hedging of natural gas for future gas years generally receive regulatory deferral accounting treatment. In general, our commodity hedging for the current gas year is completed prior to the start of the gas year, and hedge prices are reflected in our weighted-average cost of gas in the PGA filing. Hedge contracts entered into after the start of the PGA period are subject to our PGA incentive sharing mechanism in Oregon. We entered the 2017-18 and 2016-17 gas year with our forecasted sales volumes hedged at 49% and 48% in financial swap and option contracts, and 26% and 27% in physical gas supplies, respectively. Hedge contracts entered into prior to our PGA filing, in September 2017, were included in the PGA for the 2017-18 gas year. Hedge contracts entered into after our PGA filing, and related to subsequent gas years, may be included in future PGA filings and qualify for regulatory deferral.

Unrealized and Realized Gain/Loss

The following table reflects the income statement presentation for the unrealized gains and losses from our derivative instruments:

	December 31, 2017		December 31, 2016	
In thousands	Natural gas commodity	Foreign exchange	Natural gas commodity	Foreign exchange
Benefit (expense) to cost of gas	$ (26,000)	$ 107	$ 22,746	$ (130)
Operating revenues	(1,021)	—	995	—
Amounts deferred to regulatory accounts on balance sheet	26,665	(107)	(23,394)	130
Total gain (loss) in pre-tax earnings	$ (356)	$ —	$ 347	$ —

UNREALIZED GAIN/LOSS. Outstanding derivative instruments related to regulated utility operations are deferred in accordance with regulatory accounting standards. The cost of foreign currency forward and natural gas derivative contracts are recognized immediately in the cost of gas; however, costs above or below the amount embedded in the current year PGA are subject to a regulatory deferral tariff and therefore, are recorded as a regulatory asset or liability.

REALIZED GAIN/LOSS. We realized net losses of $7.8 million and $26.9 million for the years ended December 31, 2017 and 2016, respectively, from the settlement of natural gas financial derivative contracts. Realized gains and losses are recorded in cost of gas, deferred through our regulatory accounts, and amortized through customer rates in the following year.

Credit Risk Management of Financial Derivatives Instruments

No collateral was posted with or by our counterparties as of December 31, 2017 or 2016. We attempt to minimize the potential exposure to collateral calls by counterparties to manage our liquidity risk. Counterparties generally allow a certain credit limit threshold before requiring us to post collateral against loss positions. Given our counterparty credit limits and portfolio diversification, we were not subject to collateral calls in 2017 or 2016. Our collateral call exposure is set forth under credit support agreements, which generally contain credit limits. We could also be subject to collateral call exposure where we have agreed to provide adequate assurance, which is not specific as to the amount of credit limit allowed, but could potentially require additional collateral in the event of a material adverse change.

Based on current commodity financial swap and option contracts outstanding, which reflect unrealized losses of $22.3 million at December 31, 2017, we have estimated the level of collateral demands, with and without potential adequate assurance calls, using current gas prices and various credit downgrade rating scenarios for NW Natural as follows:

		Credit Rating Downgrade Scenarios			
In thousands	(Current Ratings) A+/A3	BBB+/ Baa1	BBB/ Baa2	BBB-/ Baa3	Specul-ative
With Adequate Assurance Calls	$ —	$ —	$ —	$ (5,428)	$(15,422)
Without Adequate Assurance Calls	—	—	—	(5,428)	(11,594)

Our financial derivative instruments are subject to master netting arrangements; however, they are presented on a gross basis in our consolidated balance sheets. We and our counterparties have the ability to set-off obligations to each other under specified circumstances. Such circumstances may include a defaulting party, a credit change due to a merger affecting either party, or any other termination event.

If netted by counterparty, our derivative position would result in an asset of $2.9 million and a liability of $23.3 million as of December 31, 2017. As of December 31, 2016, our derivative position would have resulted in an asset of $18.8 million and a liability of $0.7 million.

We are exposed to derivative credit and liquidity risk primarily through securing fixed price natural gas commodity swaps to hedge the risk of price increases for our natural gas purchases made on behalf of customers. We utilize master netting arrangements through International Swaps and Derivatives Association contracts to minimize this risk along with collateral support agreements with counterparties based on their credit ratings. In certain cases, we require guarantees or letters of credit from counterparties to meet our minimum credit requirement standards.

Our financial derivatives policy requires counterparties to have a certain investment-grade credit rating at the time the derivative instrument is entered into, and the policy specifies limits on the contract amount and duration based on each counterparty's credit rating. We do not speculate with derivatives; instead, we use derivatives to hedge our exposure above risk tolerance limits. Any increase in market risk created by the use of derivatives should be offset by the exposures they modify.

We actively monitor our derivative credit exposure and place counterparties on hold for trading purposes or require other forms of credit assurance, such as letters of credit, cash collateral, or guarantees as circumstances warrant. Our ongoing assessment of counterparty credit risk includes consideration of credit ratings, credit default swap spreads, bond market credit spreads, financial condition, government actions, and market news. We use a Monte-Carlo simulation model to estimate the change in credit and liquidity risk from the volatility of natural gas prices. The results of the model are used to establish earnings-at-risk trading limits. Our credit risk for all outstanding financial derivatives at December 31, 2017 extends to March 2020.

We could become materially exposed to credit risk with one or more of our counterparties if natural gas prices experience a significant increase. If a counterparty were to become insolvent or fail to perform on its obligations, we could suffer a material loss; however, we would expect such a loss to be eligible for regulatory deferral and rate recovery, subject to a prudence review. All of our existing counterparties currently have investment-grade credit ratings.

Fair Value

In accordance with fair value accounting, we include non-performance risk in calculating fair value adjustments. This includes a credit risk adjustment based on the credit spreads of our counterparties when we are in an unrealized gain position, or on our own credit spread when we are in an unrealized loss position. The inputs in our valuation models include natural gas futures, volatility, credit default swap spreads, and interest rates. Additionally, our assessment of non-performance risk is generally derived from the credit default swap market and from bond market credit spreads. The impact of the credit risk adjustments for all outstanding derivatives was immaterial to the fair value calculation at December 31, 2017. As of December 31, 2017 and 2016, the net fair value was a liability of $20.3 million and an asset of $18.1 million, respectively, using significant other observable, or Level 2, inputs. No Level 3 inputs were used in our derivative valuations, and there were no transfers between Level 1 or Level 2 during the years ended December 31, 2017 and 2016.

14. COMMITMENTS AND CONTINGENCIES

Leases

We lease land, buildings, and equipment under agreements that expire in various years, including a 99-year land lease that extends through 2108. Rental costs were $7.5 million, $6.2 million, and $5.5 million for the years ended December 31, 2017, 2016, and 2015, respectively, a portion of which is capitalized. The following table reflects the future minimum lease payments due under non-cancelable leases at December 31, 2017. These commitments relate principally to the lease of our office headquarters, underground gas storage facilities, and computer equipment.

In thousands	Operating leases	Capital leases	Minimum lease payments
2018	$ 5,378	$ 3	$ 5,381
2019	5,379	—	5,379
2020	6,945	—	6,945
2021	7,482	—	7,482
2022	7,629	—	7,629
Thereafter	169,411	—	169,411
Total	$ 202,224	$ 3	$ 202,227

In October 2017, we entered into a 20-year operating lease agreement for a new headquarters in Portland, Oregon in anticipation of the expiration of our current lease in 2020. Payments under the new lease are expected to commence in 2020. Total estimated base rent payments over the life of the lease are approximately $160 million and have been included in the table above. We have the option to extend the term of the lease for two additional seven-year periods.

Additionally, the lease was analyzed in consideration of build-to-suit lease accounting guidance, and we concluded that we are the accounting owner of the asset during construction. As a result, we recognized $0.5 million in Property, plant and equipment and an obligation in Other non-current liabilities for the same amount on our consolidated balance sheet at December 31, 2017.

Gas Purchase and Pipeline Capacity Purchase and Release Commitments

We have signed agreements providing for the reservation of firm pipeline capacity under which we are required to make fixed monthly payments for contracted capacity. The pricing component of the monthly payment is established, subject to change, by U.S. or Canadian regulatory bodies. In addition, we have entered into long-term sale agreements to release firm pipeline capacity. We also enter into short-term and long-term gas purchase agreements.

The aggregate amounts of these agreements were as follows at December 31, 2017:

In thousands	Gas Purchase Agreements	Pipeline Capacity Purchase Agreements	Pipeline Capacity Release Agreements
2018	$ 63,944	$ 79,891	$ 3,581
2019	2,729	82,129	—
2020	2,729	77,028	—
2021	2,273	65,630	—
2022	—	60,050	—
Thereafter	—	601,844	—
Total	71,675	966,572	3,581
Less: Amount representing interest	601	174,542	24
Total at present value	$ 71,074	$ 792,030	$ 3,557

Our total payments for fixed charges under capacity purchase agreements were $85.3 million for 2017, $85.0 million for 2016, and $85.2 million for 2015. Included in the amounts were reductions for capacity release sales of $4.5 million for 2017, $4.5 million for 2016, and $4.4 million for 2015. In addition, per-unit charges are required to be paid based on the actual quantities shipped under the agreements. In certain take-or-pay purchase commitments, annual deficiencies may be offset by prepayments subject to recovery over a longer term if future purchases exceed the minimum annual requirements.

Environmental Matters

Refer to Note 15 for a discussion of environmental commitments and contingencies.

15. ENVIRONMENTAL MATTERS

We own, or previously owned, properties that may require environmental remediation or action. We estimate the range of loss for environmental liabilities based on current remediation technology, enacted laws and regulations, industry experience gained at similar sites, and an assessment of the probable level of involvement and financial condition of other potentially responsible parties (PRPs). When amounts are prudently expended related to site remediation of those sites described herein, we have a recovery mechanism in place to collect 96.68% of remediation costs from Oregon customers, and we are allowed to defer environmental remediation costs allocated to customers in Washington annually until they are reviewed for prudence at a subsequent proceeding.

Our sites are subject to the remediation process prescribed by the Environmental Protection Agency (EPA) and the Oregon Department of Environmental Quality (ODEQ). The process begins with a remedial investigation (RI) to determine the nature and extent of contamination and then a risk assessment (RA) to establish whether the contamination at the site poses unacceptable risks to humans and the environment. Next, a feasibility study (FS) or an engineering evaluation/cost analysis (EE/CA) evaluates various remedial alternatives. It is at this point in the process when we are able to estimate a range of remediation costs and record a reasonable potential remediation liability, or make an adjustment to our existing liability. From this study, the regulatory agency selects a remedy and issues a Record of Decision (ROD).

After a ROD is issued, we would seek to negotiate a consent decree or consent judgment for designing and implementing the remedy. We would have the ability to further refine estimates of remediation liabilities at that time.

Remediation may include treatment of contaminated media such as sediment, soil and groundwater, removal and disposal of media, institutional controls such as legal restrictions on future property use, or natural recovery. Following construction of the remedy, the EPA and ODEQ also have requirements for ongoing maintenance, monitoring, and other post-remediation care that may continue for many years. Where appropriate and reasonably known, we will provide for these costs in our remediation liabilities described below.

Due to the numerous uncertainties surrounding the course of environmental remediation and the preliminary nature of several site investigations, in some cases, we may not be able to reasonably estimate the high end of the range of possible loss. In those cases, we have disclosed the nature of the possible loss and the fact that the high end of the range cannot be reasonably estimated where a range of potential loss is available. Unless there is an estimate within the range of possible losses that is more likely than other cost estimates within that range, we record the liability at the low end of this range. It is likely changes in these estimates and ranges will occur throughout the remediation process for each of these sites due to our continued evaluation and clarification concerning our responsibility, the complexity of environmental laws and regulations, and the determination by regulators of remediation alternatives. In addition to remediation costs, we could also be subject to Natural Resource Damages (NRD) claims from third-party tribal entities. We will assess the likelihood and probability of each claim and recognize a liability if deemed appropriate. Refer to "Other Portland Harbor" below.

Environmental Sites

The following table summarizes information regarding liabilities related to environmental sites, which are recorded in other current liabilities and other noncurrent liabilities on the balance sheet at December 31:

	Current Liabilities		Non-Current Liabilities	
In thousands	2017	2016	2017	2016
Portland Harbor site:				
Gasco/Siltronic Sediments	$ 2,683	$ 869	$ 45,346	$ 43,972
Other Portland Harbor	1,949	1,970	4,163	4,148
Gasco/Siltronic Upland site	13,422	10,657	47,835	49,183
Central Service Center site	25	73	—	—
Front Street site	1,009	906	10,757	7,786
Oregon Steel Mills	—	—	179	179
Total	$ 19,088	$ 14,475	$ 108,280	$ 105,268

PORTLAND HARBOR SITE. The Portland Harbor is an EPA listed Superfund site that is approximately 10 miles long on the Willamette River and is adjacent to NW Natural's Gasco uplands sites. We are one of over one hundred PRPs to the Superfund site. In January 2017, the EPA issued its Record of Decision, which selects the remedy fund for the clean-up of the Portland Harbor site (Portland Harbor ROD). The Portland Harbor ROD estimates the present value total cost at approximately $1.05 billion with an accuracy between -30% and +50% of actual costs.

Our potential liability is a portion of the costs of the remedy for the entire Portland Harbor Superfund site. The cost of that remedy is expected to be allocated among more than 100 PRPs. In addition, we are actively pursuing clarification and flexibility under the ROD in order to better understand our obligation under the clean-up. We are also participating in a non-binding allocation process with the other PRPs in an effort to resolve our potential liability. The Portland Harbor ROD does not provide any additional clarification around allocation of costs among PRPs and, as a result of issuance of the Portland Harbor ROD, we have not modified any of our recorded liabilities at this time.

We manage our liability related to the Superfund site as two distinct remediation projects: the Gasco/Siltronic Sediments and Other Portland Harbor projects.

Gasco/Siltronic Sediments. In 2009, NW Natural and Siltronic Corporation entered into a separate Administrative Order on Consent with the EPA to evaluate and design specific remedies for sediments adjacent to the Gasco uplands and Siltronic uplands sites. We submitted a draft EE/CA to the EPA in May 2012 to provide the estimated cost of potential remedial alternatives for this site. At this time, the estimated costs for the various sediment remedy alternatives in the draft EE/CA, for the additional studies and design work needed before the cleanup can occur, and for regulatory oversight throughout the clean-up range from $48.0 million to $350 million. We have recorded a liability of $48.0 million for the sediment clean-up, which reflects the low end of the range. At this time, we believe sediments at this site represent the largest portion of our liability related to the Portland Harbor site discussed above.

Other Portland Harbor. While we still believe liabilities associated with the Gasco/Siltronic sediments site represent our largest exposure, we do have other potential exposures associated with the Portland Harbor ROD, including NRD costs and harborwide clean-up costs (including downstream petroleum contamination), for which allocations among the PRPs have not yet been determined.

The Company and other parties have signed a cooperative agreement with the Portland Harbor Natural Resource Trustee council to participate in a phased NRD assessment to estimate liabilities to support an early restoration-based settlement of NRD claims. One member of this Trustee council, the Yakama Nation, withdrew from the council in 2009, and in 2017, filed suit against the Company and 29 other parties seeking remedial costs and NRD assessment costs associated with the Portland Harbor, set forth in the complaint. The complaint seeks recovery of alleged costs totaling $0.3 million in connection with the selection of a remedial action for the Portland Harbor as well as declaratory judgment for unspecified future remedial action costs and for costs to assess the injury, loss, or destruction of natural resources resulting from the release of hazardous substances at and from the Portland Harbor site. The Yakama Nation has filed two amended complaints addressing certain pleading defects and dismissing the State of Oregon. We have recorded a liability for NRD claims which is at the low end of the range of the potential liability; the high end of the range cannot be reasonably estimated at this time. The NRD liability is not included in the aforementioned range of costs provided in the Portland Harbor ROD.

GASCO UPLANDS SITE. A predecessor of NW Natural, Portland Gas and Coke Company, owned a former gas manufacturing plant that was closed in 1958 (Gasco site) and is adjacent to the Portland Harbor site described above. The Gasco site has been under investigation by us for environmental contamination under the ODEQ Voluntary Clean-Up Program (VCP). It is not included in the range of remedial costs for the Portland Harbor site noted above. We manage the Gasco site in two parts: the uplands portion and the groundwater source control action.

We submitted a revised Remedial Investigation Report for the uplands to ODEQ in May 2007. In March 2015, ODEQ approved the RA, enabling us to begin work on the FS in 2016. We have recognized a liability for the remediation of the uplands portion of the site which is at the low end of the range of potential liability; the high end of the range cannot be reasonably estimated at this time.

In October 2016, ODEQ and NW Natural agreed to amend their VCP agreement to incorporate a portion of the Siltronic property adjacent to the Gasco site formerly owned by Portland Gas & Coke between 1939 and 1960 into the Gasco RA and FS, excluding the uplands for Siltronic. Previously, we were conducting an investigation of manufactured gas plant constituents on the entire Siltronic uplands for ODEQ. Siltronic will be working with ODEQ directly on environmental impacts to the remainder of its property.

In September 2013, we completed construction of a groundwater source control system, including a water treatment station, at the Gasco site. We have estimated the cost associated with the ongoing operation of the system and have recognized a liability which is at the low end of the range of potential cost. We cannot estimate the high end of the range at this time due to the uncertainty associated with the duration of running the water treatment station, which is highly dependent on the remedy determined for both the upland portion as well as the final remedy for our Gasco sediment exposure.

OTHER SITES. In addition to those sites above, we have environmental exposures at three other sites: Central Service Center, Front Street, and Oregon Steel Mills. We may have exposure at other sites that have not been identified at this time. Due to the uncertainty of the design of remediation, regulation, timing of the remediation, and in the case of the Oregon Steel Mills site, pending litigation, liabilities for each of these sites have been recognized at their respective low end of the range of potential liability; the high end of the range could not be reasonably estimated at this time.

Central Service Center site. We are currently performing an environmental investigation of the property under ODEQ's Independent Cleanup Pathway. This site is on ODEQ's list of sites with confirmed releases of hazardous substances, and cleanup is necessary.

Front Street site. The Front Street site was the former location of a gas manufacturing plant we operated (the former Portland Gas Manufacturing site, or PGM). At ODEQ's request, we conducted a sediment and source control investigation and provided findings to ODEQ. In December 2015, we completed a FS on the former Portland Gas Manufacturing site.

In July 2017, ODEQ issued the PGM ROD. The ROD specifies the selected remedy, which requires a combination of dredging, capping, treatment, and natural recovery. In addition, the selected remedy also requires institutional controls and long-term inspection and maintenance. We revised the liability in the second quarter of 2017 to incorporate the estimated undiscounted cost of approximately $10.5 million for the selected remedy. Further, we have recognized an additional liability of $1.3 million for additional studies and design costs as well as regulatory oversight throughout the clean-up. We plan to complete the remedial design in 2018 and expect to construct the remedy details during 2019.

Oregon Steel Mills site. Refer to the "Legal Proceedings," below.

<u>Site Remediation and Recovery Mechanism (SRRM)</u>

We have an SRRM through which we track and have the ability to recover past deferred and future prudently incurred environmental remediation costs allocable to Oregon, subject to an earnings test, for those sites identified therein. In the February 2015 Order establishing the SRRM (2015 Order), the OPUC addressed outstanding issues related to the SRRM, which required us to forego the collection of $15 million out of approximately $95 million in total environmental remediation expenses and associated carrying costs.

As a follow-up to the 2015 Order, the OPUC issued an additional Order in January 2016 (2016 Order) regarding the SRRM implementation in which the OPUC: (1) disallowed the recovery of $2.8 million of interest earned on the previously disallowed environmental expenditure amounts; (2) clarified the state allocation of 96.68% of environmental remediation costs for all environmental sites to Oregon; and (3) confirmed our treatment of $13.8 million of expenses put into the SRRM amortization account was correct and in compliance with prior OPUC orders. As a result of the 2016 Order, we recognized a $3.3 million non-cash charge in the first quarter, of which $2.8 million is reflected in other income and expense, net and $0.5 million is included in operations and maintenance expense.

COLLECTIONS FROM OREGON CUSTOMERS. Under the SRRM collection process there are three types of deferred environmental remediation expense:

- Pre-review - This class of costs represents remediation spend that has not yet been deemed prudent by the OPUC. Carrying costs on these remediation expenses are recorded at our authorized cost of capital. The Company anticipates the prudence review for annual costs and approval of the earnings test prescribed by the OPUC to occur by the third quarter of the following year.
- Post-review - This class of costs represents remediation spend that has been deemed prudent and allowed after applying the earnings test, but is not yet included in amortization. We earn a carrying cost on these amounts at a rate equal to the five-year treasury rate plus 100 basis points.
- Amortization - This class of costs represents amounts included in current customer rates for collection and is generally calculated as one-fifth of the post-review deferred balance. We earn a carrying cost equal to the amortization rate determined annually by the OPUC, which approximates a short-term borrowing rate.

In addition to the collection amount noted above, the Order also provides for the annual collection of $5.0 million from Oregon customers through a tariff rider. As we collect amounts from customers, we recognize these collections as revenue and separately amortize an equal and offsetting amount of our deferred regulatory asset balance through the environmental remediation operating expense line shown separately in the operating expense section of the income statement.

We received total environmental insurance proceeds of approximately $150.0 million as a result of settlements from our litigation that was dismissed in July 2014. Under the 2015 OPUC Order, one-third of the Oregon allocated proceeds were applied to costs deferred through 2012 with the remaining two-thirds applied to costs at a rate of $5.0 million per year plus interest over the following 20 years. We accrue interest on the insurance proceeds in the customer's favor at a rate equal to the five-year treasury rate plus 100 basis points. As of December 31, 2017, we have applied $68.2 million of insurance proceeds to prudently incurred remediation costs allocated to Oregon.

The following table presents information regarding the total regulatory asset deferred as of December 31:

In thousands	2017	2016
Deferred costs and interest [1]	$ 45,546	$ 53,039
Accrued site liabilities [2]	126,950	119,443
Insurance proceeds and interest	(94,170)	(98,523)
Total regulatory asset deferral[1]	$ 78,326	$ 73,959
Current regulatory assets[3]	6,198	9,989
Long-term regulatory assets[3]	72,128	63,970

(1) Includes pre-review and post-review deferred costs, amounts currently in amortization, and interest, net of amounts collected from customers.

(2) Excludes 3.32% of the Front Street site liability, or $0.4 million in 2017 and $0.3 million in 2016, as the OPUC only allows recovery of 96.68% of costs for those sites allocable to Oregon, including those that historically served only Oregon customers.

(3) Environmental costs relate to specific sites approved for regulatory deferral by the OPUC and WUTC. In Oregon, we earn a carrying charge on cash amounts paid, whereas amounts accrued but not yet paid do not earn a carrying charge until expended. We also accrue a carrying charge on insurance proceeds for amounts owed to customers. In Washington, a carrying charge related to deferred amounts will be determined in a future proceeding. Current environmental costs represent remediation costs management expects to collect from customers in the next 12 months. Amounts included in this estimate are still subject to a prudence and earnings test review by the OPUC and do not include the $5 million tariff rider. The amounts allocable to Oregon are recoverable through utility rates, subject to an earnings test.

ENVIRONMENTAL EARNINGS TEST. To the extent the utility earns at or below its authorized Return of Equity (ROE), remediation expenses and interest in excess of the $5.0 million tariff rider and $5.0 million insurance proceeds are recoverable through the SRRM. To the extent the utility earns more than its authorized ROE in a year, the utility is required to cover environmental expenses and interest on expenses greater than the $10.0 million with those earnings that exceed its authorized ROE.

Under the 2015 Order, the OPUC will revisit the deferral and amortization of future remediation expenses, as well as the treatment of remaining insurance proceeds three years from the original Order, or earlier if we gain greater certainty about our future remediation costs, to consider whether adjustments to the mechanism may be appropriate.

WASHINGTON DEFERRAL. In Washington, cost recovery and carrying charges on amounts deferred for costs associated with services provided to Washington customers will be determined in a future proceeding.

Legal Proceedings

NW Natural is subject to claims and litigation arising in the ordinary course of business. Although the final outcome of any of these legal proceedings cannot be predicted with certainty, including the matter described below, we do not expect that the ultimate disposition of any of these matters will have a material effect on our financial condition, results of operations, or cash flows.

OREGON STEEL MILLS SITE. In 2004, NW Natural was served with a third-party complaint by the Port of Portland (the Port) in a Multnomah County Circuit Court case, Oregon Steel Mills, Inc. v. The Port of Portland. The Port alleges that in the 1940s and 1950s petroleum wastes generated by our predecessor, Portland Gas & Coke Company, and 10 other third-party defendants, were disposed of in a waste oil disposal facility operated by the United States or Shaver Transportation Company on property then owned by the Port and now owned by Evraz Oregon Steel Mills. The complaint seeks contribution for unspecified past remedial action costs incurred by the Port regarding the former waste oil disposal facility as well as a declaratory judgment allocating liability for future remedial action costs. No date has been set for trial. In August 2017, the case was stayed pending outcome of the Portland Harbor allocation process or other remediation. Although the final outcome of this proceeding cannot be predicted with certainty, we do not expect the ultimate disposition of this matter will have a material effect on our financial condition, results of operations, or cash flows.

For additional information regarding other commitments and contingencies, see Note 14.

NORTHWEST NATURAL GAS COMPANY
QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

In thousands, except per share data	Quarter ended March 31	June 30	September 30	December 31
2017				
Operating revenues	$ 297,323	$ 136,238	$ 88,190	$ 240,422
Net income (loss)	40,310	2,729	(8,495)	(90,167)
Basic earnings (loss) per share[(1)]	1.41	0.10	(0.30)	(3.14)
Diluted earnings (loss) per share[(1)]	1.40	0.10	(0.30)	(3.14)
2016				
Operating revenues	$ 255,529	$ 99,183	$ 87,727	$ 233,528
Net income (loss)	36,641	2,019	(8,040)	28,275
Basic earnings (loss) per share[(1)]	1.33	0.07	(0.29)	1.01
Diluted earnings (loss) per share[(1)]	1.33	0.07	(0.29)	1.00

(1) Quarterly earnings (loss) per share are based upon the average number of common shares outstanding during each quarter. Variations in earnings between quarterly periods are due primarily to the seasonal nature of our business.

NORTHWEST NATURAL GAS COMPANY
SCHEDULE II - VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

COLUMN A	COLUMN B	COLUMN C		COLUMN D	COLUMN E
		Additions		Deductions	
In thousands (year ended December 31)	Balance at beginning of period	Charged to costs and expenses	Charged to other accounts	Net write-offs	Balance at end of period
2017					
Reserves deducted in balance sheet from assets to which they apply:					
Allowance for uncollectible accounts	$ 1,290	$ 865	$ —	$ 1,199	$ 956
2016					
Reserves deducted in balance sheet from assets to which they apply:					
Allowance for uncollectible accounts	$ 870	$ 1,246	$ —	$ 826	$ 1,290
2015					
Reserves deducted in balance sheet from assets to which they apply:					
Allowance for uncollectible accounts	$ 969	$ 760	$ —	$ 859	$ 870

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

(a) Evaluation of Disclosure Controls and Procedures

Our management, under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, has completed an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended (the Exchange Act)). Based upon this evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as of the end of the period covered by this report, our disclosure controls and procedures were effective to ensure that information required to be disclosed by us and included in our reports filed or submitted under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified in the Securities and Exchange Commission (SEC) rules and forms and that such information is accumulated and communicated to management, including the Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

(b) Changes in Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in the Exchange Act Rule 13a-15(f). There have been no changes in our internal control over financial reporting that occurred during the quarter ended December 31, 2017 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

The statements contained in Exhibit 31.1 and Exhibit 31.2 should be considered in light of, and read together with, the information set forth in this Item 9(a).

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The "Information Concerning Nominees and Continuing Directors", "Corporate Governance", and "Section 16(a) Beneficial Ownership Reporting Compliance" contained in our definitive Proxy Statement for the May 24, 2018 Annual Meeting of Shareholders is hereby incorporated by reference.

Name	Age at Dec. 31, 2017	Positions held during last five years
David H. Anderson	56	Chief Executive Officer and President (2016-); Chief Operating Officer and President (2015-2016); Executive Vice President and Chief Operating Officer (2014-2015); Executive Vice President Operations and Regulation (2013-2014); Senior Vice President and Chief Financial Officer (2004-2013).
Frank H. Burkhartsmeyer(1)	53	Senior Vice President and Chief Financial Officer (2017-); President and Chief Executive Officer of Renewables, Avangrid Renewables (2015-2017); Senior Vice President of Finance, Iberdrola Renewables Holdings, Inc. (2012-2015); Vice President, Strategy, Planning & Market Fundamentals, Iberdrola Renewables Holdings, Inc. (2005- 2012).
Brody J. Wilson(1)	38	Vice President, Chief Accounting Officer, Controller and Treasurer (2017-); Chief Financial Officer (Interim), Treasurer, Chief Accounting Officer and Controller (2016-2017); Chief Accounting Officer, Controller and Assistant Treasurer (2016); Controller (2013-2015); Acting Controller (2013); Accounting Director (2012-2013); Senior Manager, PriceWaterhouseCoopers LLP (2009-2012); Manager, PriceWaterhouseCoopers LLP (2007-2009).
Lea Anne Doolittle	62	Senior Vice President and Chief Administrative Officer (2013-); Senior Vice President (2008-2013); Vice President, Human Resources (2000-2007).
James R.Downing	48	Vice President and Chief Information Officer (2017-); Chief Information Officer, WorleyParsons (America's Division) (2016-2017); Executive Service Delivery Manager for SAP, British Petroleum (2011-2015).
Kimberly A. Heiting(2)(3)	48	Vice President, Communications and Chief Marketing Officer (2015-); Chief Marketing & Communications Officer (2013-2014); Chief Corporate Communications Officer (2011-2013); Communications Director (2005-2011).
MardiLyn Saathoff	61	Senior Vice President, Regulation and General Counsel (2016-); Senior Vice President and General Counsel (2015-2016); Vice President, Legal, Risk and Compliance (2013-2014); Deputy General Counsel (2010-2013); Chief Governance Officer and Corporate Secretary (2008-2014).
Grant M. Yoshihara(3)	62	Senior Vice President, Utility Operations (2016-); Vice President, Utility Operations (2007-2016); Managing Director, Utility Services (2005-2006); Director, Utility Services (2004-2005).
Shawn M. Filippi	45	Vice President, Chief Compliance Officer and Corporate Secretary (2016-); Vice President and Corporate Secretary (2015-2016); Senior Legal Counsel (2011-2014); Assistant Corporate Secretary (2010-2014); Associate Legal Counsel (2005-2010).
Thomas J. Imeson	67	Vice President of Public Affairs (2014-); Director of Public Affairs, Port of Portland (2006-2014).
Justin Palfreyman	39	Vice President, Strategy and Business Development (2017-);Vice President, Business Development (2016-2017); Director, Power, Energy and Infrastructure Group, Lazard, Freres & Co. (2009-2016).
Lori Russell	58	Vice President, Utility Services (2016-); Utility Field Operations Director (2013-2016); Serve Customer Process Director (2008-2013).
David A. Weber	58	President and Chief Executive Officer, NW Natural Gas Storage, LLC and Gill Ranch Storage, LLC (2012-); Interim President and Chief Executive Officer, NW Natural Gas Storage, LLC and Gill Ranch Storage, LLC (2011-2012); Chief Operating Officer, NW Natural Gas Storage, LLC and Gill Ranch Storage, LLC (2010-2011); Managing Director of Information Services and Chief Information Officer (2005-2011); Director of Information Services and Chief Information Officer (2001-2005).

(1) Frank H. Burkhartsmeyer was appointed Senior Vice President and Chief Financial Office effective May 17, 2017, replacing Brody J. Wilson, who had been serving as Chief Financial Office on an interim basis. Effective May 17, 2017, Mr. Wilson was appointed Vice President, Chief Accounting Officer, Controller, and Treasurer.
(2) Kimberly A. Heiting was appointed Senior Vice President, Communications and Chief Marketing Officer effective January 1, 2018.
(3) Grant M. Yoshihara announced his intention to retire effective March 31, 2018. The Board of Directors appointed Kimberly A. Heiting as Senior Vice President, Operations and Chief Marketing Officer and Jon Huddleston Vice President, Engineering and Utility Operations, effective March 31, 2018.

Each executive officer serves successive annual terms; present terms end on May 24, 2018. There are no family relationships among our executive officers, directors or any person chosen to become one of our officers or directors. NW Natural has adopted a Code of Ethics (Code) applicable to all employees and officers that is available on our website at www.nwnatural.com. We intend to disclose on our website at www.nwnatural.com any amendments to the Code or waivers of the Code for executive officers and directors.

ITEM 11. EXECUTIVE COMPENSATION

The information concerning "Executive Compensation", "Report of the Organization and Executive Compensation Committee", and "Compensation Committee Interlocks and Insider Participation" contained in our definitive Proxy Statement for the May 24, 2018 Annual Meeting of Shareholders is hereby incorporated by reference. Information related to Executive Officers as of December 31, 2017 is reflected in Part III, Item 10, above.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The following table sets forth information regarding compensation plans under which equity securities of NW Natural are authorized for issuance as of December 31, 2017 (see Note 6 to the Consolidated Financial Statements):

Plan Category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights	(b) Weighted-average exercise price of outstanding options, warrants and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders:			
LTIP [1][2]	171,995	n/a	626,960
Restated Stock Option Plan	91,688	$ 44.43	—
Employee Stock Purchase Plan	22,804	56.53	37,857
Equity compensation plans not approved by security holders:			
Executive Deferred Compensation Plan (EDCP)[3]	1,132	n/a	n/a
Directors Deferred Compensation Plan (DDCP)[3]	42,936	n/a	n/a
Deferred Compensation Plan for Directors and Executives (DCP)[4]	176,265	n/a	n/a
Total	506,820		664,817

(1) Awards may be granted under the LTIP as Performance Share Awards, Restricted Stock Units, or stock options. Shares issued pursuant to Performance Share Awards and Restricted Stock Units under the LTIP do not include an exercise price, but are payable when the award criteria are satisfied. The number of shares shown in column (a) include 84,522 Restricted Stock Units and 87,473 Performance Share Awards, reflecting the number of shares to be issued as targeted performance share awards under outstanding Performance Share Awards. If the maximum awards were paid pursuant to the Performance Share Awards outstanding at December 31, 2017, the number of shares shown in column (a) would increase by 87,473 shares, reflecting the maximum share award of 200% of target, and the number of shares shown in column (c) would decrease by the same amount of shares. No stock options or other types of award have been issued under the LTIP.

(2) The number of shares shown in column (c) includes shares that are available for future issuance under the LTIP as Restricted Stock Units, Performance Share Awards, or stock options at December 31, 2017.

(3) Prior to January 1, 2005, deferred amounts were credited, at the participant’s election, to either a “cash account” or a “stock account.” If deferred amounts were credited to stock accounts, such accounts were credited with a number of shares of NW Natural common stock based on the purchase price of the common stock on the next purchase date under our Dividend Reinvestment and Direct Stock Purchase Plan, and such accounts were credited with additional shares based on the deemed reinvestment of dividends. Cash accounts are credited quarterly with interest at a rate equal to Moody’s Average Corporate Bond Yield plus two percentage points, subject to a 6% minimum rate. At the election of the participant, deferred balances in the stock accounts are payable after termination of Board service or employment in a lump sum, in installments over a period not to exceed 10 years in the case of the DDCP, or 15 years in the case of the EDCP, or in a combination of lump sum and installments. Amounts credited to stock accounts are payable solely in shares of common stock and cash for fractional shares, and amounts in the above table represent the aggregate number of shares credited to participants' stock accounts. We have contributed common stock to the trustee of the Umbrella Trusts such that the Umbrella Trusts hold approximately the number of shares of common stock equal to the number of shares credited to all participants’ stock accounts.

(4) Effective January 1, 2005, the EDCP and DDCP were closed to new participants and replaced with the DCP. The DCP continues the basic provisions of the EDCP and DDCP under which deferred amounts are credited to either a “cash account” or a “stock account.” Stock accounts represent a right to receive shares of NW Natural common stock on a deferred basis, and such accounts are credited with additional shares based on the deemed reinvestment of dividends. Effective January 1, 2007, cash accounts are credited quarterly with interest at a rate equal to Moody’s Average Corporate Bond Yield. Our obligation to pay deferred compensation in accordance with the terms of the DCP will generally become due on retirement, death, or other termination of service, and will be paid in a lump sum or in installments of five, 10, or 15 years as elected by the participant in accordance with the terms of the DCP. Amounts credited to stock accounts are payable solely in shares of common stock and cash for fractional shares, and amounts in the above table represent the aggregate number of shares credited to participants' stock accounts. We have contributed common stock to the trustee of the Supplemental Trust such that this trust holds approximately the number of common shares equal to the number of shares credited to all participants' stock accounts. The right of each participant in the DCP is that of a general, unsecured creditor of the Company.

The information captioned “Beneficial Ownership of Common Stock by Directors and Executive Officers” and "Security Ownership of Common Stock of Certain Beneficial Owners" contained in our definitive Proxy Statement for the May 24, 2018 Annual Meeting of Shareholders is incorporated herein by reference.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information captioned "Transactions with Related Persons" and "Corporate Governance" in the Company's definitive Proxy Statement for the May 24, 2018 Annual Meeting of Shareholders is hereby incorporated by reference.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information captioned "2017 and 2016 Audit Firm Fees" in the Company's definitive Proxy Statement for the May 24, 2018 Annual Meeting of Shareholders is hereby incorporated by reference.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) The following documents are filed as part of this report:

1. A list of all Financial Statements and Supplemental Schedules is incorporated by reference to Item 8.

2. List of Exhibits filed:

   Reference is made to the Exhibit Index commencing on page 95.

ITEM 16. FORM 10-K SUMMARY

None.

NORTHWEST NATURAL GAS COMPANY

Exhibit Index to Annual Report on Form 10-K
For the Fiscal Year Ended December 31, 2017

Exhibit Number	Document
*3a.	Restated Articles of Incorporation, as filed and effective May 31, 2006 and amended June 3, 2008 (incorporated herein by reference to Exhibit 3.1 to Form 10-Q for the quarter ended June 30, 2008, File No. 1-15973).
*3b.	Bylaws as amended December 21, 2017 (incorporated herein by reference to Exhibit 3.1 to Form 8-K dated December 21, 2017, File No. 1-15973).
*4a.	Copy of Mortgage and Deed of Trust, dated as of July 1, 1946, to Bankers Trust (to whom Deutsche Bank Trust Company Americas is now successor), Trustee (incorporated herein by reference to Exhibit 7(j) in File No. 2-6494); and copies of Supplemental Indentures Nos. 1 through 14 to the Mortgage and Deed of Trust, dated respectively, as of June 1, 1949, March 1, 1954, April 1, 1956, February 1, 1959, July 1, 1961, January 1, 1964, March 1, 1966, December 1, 1969, April 1, 1971, January 1, 1975, December 1, 1975, July 1, 1981, June 1, 1985 and November 1, 1985 (incorporated herein by reference to Exhibit 4(d) in File No. 33-1929); Supplemental Indenture No. 15 to the Mortgage and Deed of Trust, dated as of July 1, 1986 (filed as Exhibit 4(c) in File No. 33-24168); Supplemental Indentures Nos. 16, 17 and 18 to the Mortgage and Deed of Trust, dated, respectively, as of November 1, 1988, October 1, 1989 and July 1, 1990 (incorporated herein by reference to Exhibit 4(c) in File No. 33-40482); Supplemental Indenture No. 19 to the Mortgage and Deed of Trust, dated as of June 1, 1991 (incorporated herein by reference to Exhibit 4(c) in File No. 33-64014); Supplemental Indenture No. 20 to the Mortgage and Deed of Trust, dated as of June 1, 1993 (incorporated herein by reference to Exhibit 4(c) in File No. 33-53795); Supplemental Indenture No. 21 to the Mortgage and Deed of Trust, dated as of October 15, 2012 (incorporated herein by reference to Exhibit 4.1 to Form 8-K dated October 26, 2012, File No. 1-15973); and Supplemental Indenture No. 22 to the Mortgage and Deed of Trust, dated as of November 1, 2016 (incorporated herein by reference to Exhibit 4.1 to Form 10-Q for the quarter ended September 30, 2016, File No. 1-15973).
*4b.	Form of Secured Medium-Term Notes, Series B (incorporated herein by reference to Exhibit 4.1 to Form 8-K dated October 4, 2004, File No. 1-15973).
*4c.	Copy of Indenture, dated as of June 1, 1991, between the Company and Bankers Trust Company, Trustee, relating to the Company's Unsecured Medium-Term Notes (incorporated herein by reference to Exhibit 4(e) in File No. 33-64014).
*4d.	Form of Credit Agreement among Northwest Natural Gas Company and the parties thereto, with JPMorgan Chase Bank, N.A. as administrative agent and U.S. Bank, N.A. and Wells Fargo Bank, N.A. as co-syndication agents, dated as of December 20, 2012 (incorporated herein by reference to Exhibit 4.1 to Form 8-K dated December 21, 2012, File No.1-15973).
*4e.	Form of Letter Agreement, between each of JPMorgan Chase Bank, N.A., Bank of America, N.A., Canadian Imperial Bank of Commerce, Royal Bank of Canada, TD Bank, N.A., Union Bank, N.A., US Bank, N.A., and Wells Fargo Bank, N.A., with JPMorgan Chase Bank, N.A. as Administrative Agent, extending the maturity date of the Credit Agreement between Northwest Natural Gas Company and each financial institution, effective as of December 20, 2013 (incorporated herein by reference to Exhibit 4k to Form 10-K for 2013, File No. 1-15973).
*4f.	Form of Letter Agreement, between each of JPMorgan Chase Bank, N.A., Bank of America, N.A., Canadian Imperial Bank of Commerce, Royal Bank of Canada, TD Bank, N.A., Union Bank, N.A., US Bank, N.A., and Wells Fargo Bank, N.A., with JPMorgan Chase Bank, N.A. as Administrative Agent, extending the maturity date of the Credit Agreement between Northwest Natural Gas Company and each financial institution, effective as of December 20, 2014 (incorporated herein by reference to Exhibit 4m to Form 10-K for 2014, File No. 1-15973).
*4g.	First Amendment to Credit Agreement, between the Company JPMorgan Chase Bank, N.A., Bank of America, N.A., Canadian Imperial Bank of Commerce, Royal Bank of Canada, TD Bank, N.A., Union Bank, N.A., US Bank, N.A., and Wells Fargo Bank, N.A., with JPMorgan Chase Bank, N.A. as Administrative Agent, dated as of December 20, 2014 (incorporated herein by reference to Exhibit 4n to Form 10-K for 2014, File No. 1-15973).
12	Statement re computation of ratios of earnings to fixed charges.
21	Subsidiaries of Northwest Natural Gas Company.

23 Consent of PricewaterhouseCoopers LLP.

31.1 Certification of Principal Executive Officer Pursuant to Rule 13a-14(a)/15-d-14(a), Section 302 of the Sarbanes-Oxley Act of 2002.

31.2 Certification of Principal Financial Officer Pursuant to Rule 13a-14(a)/15-d-14(a), Section 302 of the Sarbanes-Oxley Act of 2002.

**32.1 Certification of Principal Executive Officer and Principal Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

<u>Executive Compensation Plans and Arrangements:</u>

*10a. Executive Supplemental Retirement Income Plan 2010 Restatement (incorporated herein by reference to Exhibit 10b. to Form 10-K for 2009, File No. 1-15973).

*10b. Supplemental Executive Retirement Plan, 2011 Restatement (incorporated herein by reference to Exhibit 10.1 to Form 10-Q for the quarter ended September 30, 2011, File No. 1-15973).

*10c. Northwest Natural Gas Company Supplemental Trust, effective January 1, 2005, restated as of December 15, 2005 (incorporated herein by reference to Exhibit 10.7 to Form 8-K dated December 16, 2005, File No. 1-15973).

*10d. Northwest Natural Gas Company Umbrella Trust for Directors, effective January 1, 1991, restated as of December 15, 2005 (incorporated herein by reference to Exhibit 10.5 to Form 8-K dated December 16, 2005, File No. 1-15973).

*10e. Northwest Natural Gas Company Umbrella Trust for Executives, effective January 1, 1988, restated as of December 15, 2005 (incorporated herein by reference to Exhibit 10.6 to Form 8-K dated December 16, 2005, File No. 1-15973).

*10f. Restated Stock Option Plan, as amended effective December 14, 2006 (incorporated herein by reference to Exhibit 10c. to Form 10-K for 2006, File No. 1-15973).

*10g. Form of Restated Stock Option Plan Agreement (incorporated herein by reference to Exhibit 10h. to Form 10-K for 2009, File No. 1-15973).

*10h. Executive Deferred Compensation Plan, effective as of January 1, 1987, restated as of February 26, 2009 (incorporated herein by reference to Exhibit 10e. to Form 10-K for 2008, File No. 1-15973).

*10i. Directors Deferred Compensation Plan, effective June 1, 1981, restated as of February 26, 2009 (incorporated herein by reference to Exhibit 10f. to Form 10-K for 2008, File No. 1-15973).

*10j. Deferred Compensation Plan for Directors and Executives, effective January 1, 2005, restated as of July 28, 2016 (incorporated herein by reference to Exhibit 10.3 to Form 10-Q for the quarter ended June 30, 2016, File No. 1-15973).

*10k. Form of Indemnity Agreement as entered into between the Company and each director and certain executive officers (incorporated herein by reference to Exhibit 10l. to Form 10-K for 2009, File No. 1-15973).

*10l. Form of Indemnity Agreement as entered into between the Company and certain executive officers (incorporated herein by reference to Exhibit 10l.(1) to Form 10-K for 2009, File No. 1-15973).

*10m. Non-Employee Directors Stock Compensation Plan, as amended effective December 15, 2005 (incorporated herein by reference to Exhibit 10.2 to Form 8-K dated December 16, 2005, File No. 1-15973).

*10n.	Executive Annual Incentive Plan, effective February 23, 2012, as amended effective January 1, 2016 (incorporated herein by reference to Exhibit 10p. to Form 10-K for 2015, File No. 1-15973).
10o.	Executive Annual Incentive Plan, effective January 1, 2017 (incorporated herein by reference to Exhibit 10o. to Form 10-K for 2016, File No. 1-15973).
10p.	Executive Annual Incentive Plan, effective January 1, 2018.
*10q.	Form of Change in Control Severance Agreement between the Company and each executive officer (incorporated herein by reference to Exhibit 10o. to Form 10-K for 2008, File No. 1-15973).
*10r.	Northwest Natural Gas Company Long Term Incentive Plan, as amended and restated effective May 24, 2012 (incorporated herein by reference to Exhibit 10r to Form 10-K for 2012, File No. 1-15973).
10s.	Northwest Natural Gas Company Long Term Incentive Plan, as amended and restated effective May 25, 2017.
*10t.	Form of Long Term Incentive Award Agreement under the Long Term Incentive Plan (2015-2017) (incorporated by reference to Exhibit 10w. to Form 10-K for 2014, File No. 1-15973).
*10u.	Form of Long Term Incentive Award Agreement under the Long Term Incentive Plan (2016-2018) (incorporated herein by reference to Exhibit 10w. to Form 10-K for 2015, File No. 1-15973).
*10v.	Form of Long Term Incentive Award Agreement under the Long Term Incentive Plan between the Company and an Executive Officer (2016-2018) (incorporated herein by reference to Exhibit 10x. to Form 10-K for 2015, File No. 1-15973).
*10w.	Agreement to Amend the Long Term Incentive Award Agreement, under the Long Term Incentive Plan dated February 25, 2016 by and between the Company and an executive officer (incorporated herein by reference to Exhibit 10y. to Form 10-K for 2015, File No. 1-15973).
*10x.	Form of Long Term Incentive Award Agreement under Long Term Incentive Plan (2017-2019) (incorporated herein by reference to Exhibit 10x. to Form 10-K for 2016, File No. 1-15973).
10y.	Form of Long Term Incentive Award Agreement under Long Term Incentive Plan (2018-2020).
*10z.	Form of Consent dated December 14, 2006 entered into by each executive officer with respect to amendments to the Executive Supplemental Retirement Income Plan, the Supplemental Executive Retirement Plan and certain change in control severance agreements (incorporated herein by reference to Exhibit 10.1 to Form 8-K dated December 19, 2006, File No. 1-15973).
*10aa.	Consent to Amendment of Deferred Compensation Plan for Directors and Executives, dated February 28, 2008 entered into by each executive officer (incorporated herein by reference to Exhibit 10bb to Form 10-K for 2007, File No. 1-15973).
10bb.	Form of Restricted Stock Unit Award Agreement under Long Term Incentive Plan (2018).
*10cc.	Corrected Form of Restricted Stock Unit Award Agreement under Long Term Incentive Plan (2017)(incorporated herein by reference to Exhibit 10.1 to Form 10-Q for the quarter ended March 31, 2017, File No. 1-15973).
*10dd.	Form of Restricted Stock Unit Award Agreement under Long Term Incentive Plan (2016) (incorporated herein by reference to Exhibit 10bb. to Form 10-K for 2015, File No. 1-15973).

*10ee. Form of Amendment to Restricted Stock Unit Award Agreements (2013, 2014 and 2015) (incorporated herein by reference to Exhibit 10cc to Form 10-K for 2016, File No. 1-15973).

*10ff. Form of Restricted Stock Unit Award Agreement under the Long Term Incentive Plan (2013, 2014 and 2015) (incorporated herein by reference to Exhibit 10aa. to Form 10-K for 2012, File No. 1-15973).

*10gg. Form of Special Restricted Stock Unit Award Agreement under the Long Term Incentive Plan between the Company and an executive officer (incorporated herein by reference to Exhibit 10a. to Form 10-Q for the quarter ended March 31, 2014, File No. 1-15973).

*10hh. Form of Director Restricted Stock Unit Award Agreement under the Long Term Incentive Plan (incorporated herein by reference to Exhibit 10.1 to Form 10-Q for the quarter ended June 30, 2017, File No 1-15973).

*10ii. Form of Director Restricted Stock Unit Award Agreement under Long Term Incentive Plan (incorporated herein by reference to Exhibit 10a. to Form 10-Q for the quarter ended March 31, 2016, File No. 1-15973).

*10jj. Severance Agreement between Northwest Natural Gas Company and an executive officer, dated August 1, 2016 (incorporated herein by reference to Exhibit 10.1 to Form 8-K dated July 29, 2016, File No. 1-15973).

*10kk. Form of Restricted Stock Unit Award Agreement between the Company and an executive officer dated as of July 27, 2016 (incorporated herein by reference to Exhibit 10.1 to Form 10-Q for the quarter ended June 30, 2016, File No. 1-15973).

*10ll. Amended and Restated Cash Retention Agreement between the Company and an executive officer, dated as of July 28, 2016 (incorporated herein by reference to Exhibit 10.2 to Form 10-Q for the quarter ended June 30, 2016, File No. 1-15973).

*10mm. Form of Special Restricted Stock Unit Award Agreement under Long Term Incentive Plan between the Company and an executive officer, dated as of September 30, 2016 (incorporated herein by reference to Exhibit 10.1 to Form 10-Q for the quarter ended September 30, 2016, File No. 1-15973).

*10nn. Form of Severance Agreement between the Company and an executive officer, dated May 17, 2017 (incorporated herein by reference to Exhibit 10.1 to Form 8-K dated April 24, 2017, File No. 1-15973).

*10oo. Form of Special Restricted Stock Unit Agreement between the Company and an executive officer, dated May 17, 2017 (incorporated herein by reference to Exhibit 10.2 to Form 8-K dated April 24, 2017, File No. 1-15973).

*10pp. Form of Hire-On Bonus Agreement between the Company and an executive officer, dated May 17, 2017 (incorporated herein by reference to Exhibit 10.3 to Form 8-K dated April 24, 2017, File No. 1-15973).

10qq. Form of Special Restricted Stock Unit Agreement between the Company and an executive officer, dated September 30, 2016.

10rr. Form of Hire-On Bonus Agreement between the Company and an executive officer, date September 30, 2016.

10ss. Cash Retention Agreement between the Company and an executive officer, dated as of March 1, 2018.

*10tt. Annual Incentive Plan for NW Natural Gas Storage, LLC, as amended effective January 1, 2017 (incorporated herein by reference to Exhibit 10oo. to Form 10-K for 2016, File No. 1-15973).

*10uu. Long Term Incentive Plan for NW Natural Gas Storage, LLC, as amended effective January 1, 2016 (incorporated herein by reference to Exhibit 10pp. to Form 10-K for 2016, File No. 1-15973).

101. The following materials from Northwest Natural Gas Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2017, formatted in Extensible Business Reporting Language (XBRL):
(i) Consolidated Statements of Income;
(ii) Consolidated Balance Sheets;
(iii) Consolidated Statements of Cash Flows; and
(iv) Related notes.

*Incorporated herein by reference as indicated
**Pursuant to Item 601(b)(32)(ii) of Regulation S-K, this certificate is not being "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

NORTHWEST NATURAL GAS COMPANY

By: /s/ David H. Anderson
David H. Anderson
President and Chief Executive Officer
Date: February 23, 2018

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the date indicated.

Signature	Title	Date
/s/ David H. Anderson David H. Anderson President and Chief Executive Officer	Principal Executive Officer and Director	February 23, 2018
/s/ Frank H. Burkhartsmeyer Frank H. Burkhartsmeyer Senior Vice President and Chief Financial Officer	Principal Financial Officer	February 23, 2018
/s/ Brody J. Wilson Brody J. Wilson Vice President, Treasurer, Chief Accounting Officer and Controller	Principal Accounting Officer	February 23, 2018
/s/ Timothy P. Boyle Timothy P. Boyle	Director	)))
/s/ Martha L. Byorum Martha L. Byorum	Director	)))
/s/ John D. Carter John D. Carter	Director	)))
/s/ Mark S. Dodson Mark S. Dodson	Director	)) February 23, 2018
/s/ C. Scott Gibson C. Scott Gibson	Director	)))
/s/ Tod R. Hamachek Tod R. Hamachek	Director	)))
/s/ Jane L. Peverett Jane L. Peverett	Director	)))
/s/ Kenneth Thrasher Kenneth Thrasher	Director	)))
/s/ Malia H. Wasson Malia H. Wasson	Director	))

EXHIBIT 12

NORTHWEST NATURAL GAS COMPANY

Ratios of Earnings to Fixed Charges

(Unaudited)

In thousands, except share data	Year Ended December 31, 2017	2016	2015	2014	2013
Fixed Charges, as defined:					
Interest on Long-Term Debt	$ 36,809	$ 34,508	$ 37,918	$ 40,066	$ 40,825
Other Interest	2,274	3,404	3,173	2,718	2,709
Amortization of Debt Discount and Expense	2,017	1,671	1,760	1,963	1,877
Capitalized Interest	2,598	—	—	—	—
Interest Portion of Rentals	2,574	2,048	1,976	2,302	1,910
Total Fixed Charges, as defined	46,272	41,631	44,827	47,049	47,321
Earnings, as defined:					
Net Income (Loss)	(55,623)	58,895	53,703	58,692	60,538
Taxes on Income	(30,757)	40,714	35,753	41,643	41,705
Fixed Charges, as above	46,272	41,631	44,827	47,049	47,321
Total Earnings (Losses), as defined	$ (40,108)	$ 141,240	$ 134,283	$ 147,384	$ 149,564
Ratios of Earnings to Fixed Charges	*	3.39	3.00	3.13	3.16

* In 2017, earnings were insufficient to cover fixed charges by approximately $86.4 million primarily due to the impairment of long-lived assets at the Gill Ranch Facility.

EXHIBIT 21

SUBSIDIARIES OF NORTHWEST NATURAL GAS COMPANY

an Oregon Corporation

Name of Subsidiary	Jurisdiction Organized
Gill Ranch Storage, LLC	Oregon
NW Natural Energy, LLC	Oregon
NW Natural Gas Storage, LLC	Oregon
NNG Financial Corporation	Oregon
Trail West Holdings, LLC	Delaware
Trail West Pipeline, LLC	Delaware
BL Credit Holdings, LLC	Delaware
Northwest Biogas, LLC	Oregon
KB Pipeline Company	Oregon
Northwest Energy Corporation	Oregon
Northwest Energy Sub Corporation	Oregon
NWN Gas Reserves LLC	Oregon
NW Natural Water Company, LLC	Oregon
FWC Merger Sub, Inc.	Idaho

EXHIBIT 23

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-8 (Nos. 333-70218, 333-100885, 333-120955, 333-134973, 333-139819, 333-180350, 333-187005, 333-214425, and 333-221347) and Form S-3 (No. 333-214496) of Northwest Natural Gas Company of our report dated February 23, 2018 relating to the financial statements, financial statement schedule and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP

Portland, Oregon
February 23, 2018

EXHIBIT 31.1

CERTIFICATION

I, David H. Anderson, certify that:

1. I have reviewed this annual report on Form 10-K of Northwest Natural Gas Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 23, 2018

/s/ David H. Anderson
David H. Anderson
President and Chief Executive Officer

EXHIBIT 31.2

CERTIFICATION

I, Frank H. Burkhartsmeyer, certify that:

1. I have reviewed this annual report on Form 10-K for Northwest Natural Gas Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 23, 2018

/s/ Frank H. Burkhartsmeyer
Frank H. Burkhartsmeyer
Senior Vice President and Chief Financial Officer

EXHIBIT 32.1

NORTHWEST NATURAL GAS COMPANY

Certificate Pursuant to Section 906
of Sarbanes – Oxley Act of 2002

Each of the undersigned, DAVID H. ANDERSON, Chief Executive Officer, and FRANK H. BURKHARTSMEYER, Senior Vice President and Chief Financial Officer of NORTHWEST NATURAL GAS COMPANY (the Company), DOES HEREBY CERTIFY that:

1. The Company's Annual Report on Form 10-K for the year ended December 31, 2017 (the Report) fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

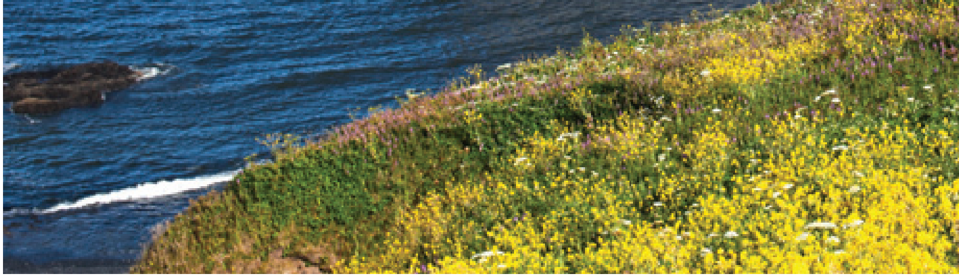
2. Information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

IN WITNESS WHEREOF, each of the undersigned has caused this instrument to be executed this 23th day of February 2018.

/s/ David H. Anderson
David H. Anderson
Chief Executive Officer

/s/ Frank H. Burkhartsmeyer
Frank H. Burkhartsmeyer
Senior Vice President and Chief Financial Officer

A signed original of this written statement required by Section 906 of the Sarbanes-Oxley Act of 2002 has been provided to Northwest Natural Gas Company and will be retained by Northwest Natural Gas Company and furnished to the Securities and Exchange Commission or its staff upon request.



COMMUNITY & SUSTAINABILITY REPORT

Learn more about NW Natural's community involvement and philanthropic contributions, environmental stewardship, employee safety efforts and other company initiatives.

View the Community & Sustainability Annual Report at:
nwnatural.com/aboutnwnatural/community

»INVESTOR AND SHAREHOLDER **INFORMATION**

STOCK TRANSFER AGENT AND REGISTRAR

For common stock:
American Stock Transfer
& Trust Company
6201 15th Avenue
Brooklyn, NY 11219
(888) 777-0321
web: astfinancial.com
email: info@astfinancial.com

TRUSTEE AND BOND PAYING AGENT

For bond issues:
Deutsche Bank
Trust Company Americas
60 Wall Street
New York, NY 10005
(800) 735-7777

NIKKI SPARLEY
Director, Investor Relations
Toll free (800) 422-4012, Ext. 2530
Direct (503) 721-2530
nikki.sparley@nwnatural.com

CHU LEE
Manager, Shareholder Services
Toll free (800) 422-4012, Ext. 2402
Direct (503) 220-2402
chu.lee@nwnatural.com

LOW-INCOME PROGRAMS

NW Natural helps low-income customers manage their bills through a variety of programs. Shareholders and customers support the Gas Assistance Program, which supplements federal and state assistance programs. In addition, the Oregon Low-Income Gas Assistance Program uses public purpose fees to help low-income customers pay their utility bills. The Oregon Low-Income Energy Efficiency Program, also paid for by public purpose charges, helps customers in need acquire high-efficiency equipment and weatherization upgrades.

View the Low-Income Programs at:
nwnatural.com/residential

ENERGY-EFFICIENCY PROGRAMS

NW Natural partners with Energy Trust of Oregon to offer our Oregon and Washington customers energy-efficiency programs and services. Learn more about the results of these programs and the benefits to our customers.

View the Energy Trust of Oregon Annual Report at:
nwnatural.com/residential

NW Natural®

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